COAL AS AN ALTERNATE
FUEL FOR NAVAL VESSELS.

Charles Brett Rowland

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COAL AS AN ALTERNATE FUEL FOR NAVAL VESSELS

by

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Lieutenant Commander, United States Navy

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1967

SUBMITTED IN PARTIAL FULFILLMENT

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Coal As An Alternate Fuel For Naval Vessels

By Charles Brett Rowland

Submitted to the Department of Ocean Engineering on May 2, 1978; in partial fulfillment of the requirements for the Degree of Ocean Engineer and the Degree of Master of Science in Shipping and Shipbuilding Management.

Abstract

This thesis examines the possible uses of coal and coal derived fuels for propulsion of the ships of the United States Navy. The need for this study was precipitated by the worsening supply of oil in the world.

Included is a review of the world energy problem, and estimates of when real shortages in petroleum can be expected.

Atmospheric fluidized bed combustors and pulverized coal furnaces are examined as modern methods of solid coal firing. Their impact on ship size as compared to more conventional means of powering, was examined through use of a computer aided ship synthesis model.

The use of coal for existing ships was limited to a discussion of coal-derived liquid fuels and coal/oil slurries.

Thesis Supervisor: A. Douglas Carmichael

Title: Professor of Power Engineering

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I. INTRODUCTION

The purpose of this thesis is to examine the possible uses of coal and coal derived fuels for propulsion of the United States Navy's ships.

The need for this study was precipitated by the worsening supply of oil in the world. History may record 1973 as the year of the energy crisis, but most people in the energy business were aware of an energy supply problem before 1973. Perhaps that year was important because it was the start of energy awareness for the masses. The facts were driven sharply home by the quadrupling of the price of the raw product. Cheap petroleum was gone forever and the world was introduced to a new type of warfare. Petroleum price was the weapon of this war to be waged by the oil producers of the world. The effects were compounded in the United States where increasing demands were placed upon our petroleum production capacity by environmental requirements.

As unpalatable as the current price of oil is, it is not the real problem. The real problem is that the reserves of oil are running out. No one can predict accurately when shortages will occur because of the numbers of variables that affect demand. But the 1980's would be a good guess as to a period when demand will equal supply. Even

with this country's vast reserves of petroleum we are not close to self sufficiency. In the winter months of 1977 the U.S. was importing fifty percent of consumption.

The Navy must be vitally concerned with future patterns of fuel reserves and fuel consumption because of two factors. The first is the long lead times involved on acquiring a new ship and the extended operational life of the vessel after delivery. The propulsion system selected for a vessel today could be expected to provide service on that ship forty years in the future. Presently from concept formulation to delivery of a ship it takes about fourteen years. The ship will then see approximately thirty years of service. Therefore the Navy is now designing ships that will be in operation in a much different world energywise, than that which currently exists. Secondly the Navy is not a major fuel user. It therefore is a follower as far as fuel type development is concerned. Because of this the Navy must be able to include a flexibility in its design, to be capable of using the fuels of the future. The Navy must design with this forcast in mind. So as to not have to forecast in a vacuum, the Navy can choose a region of certainty for a choice of fuel.

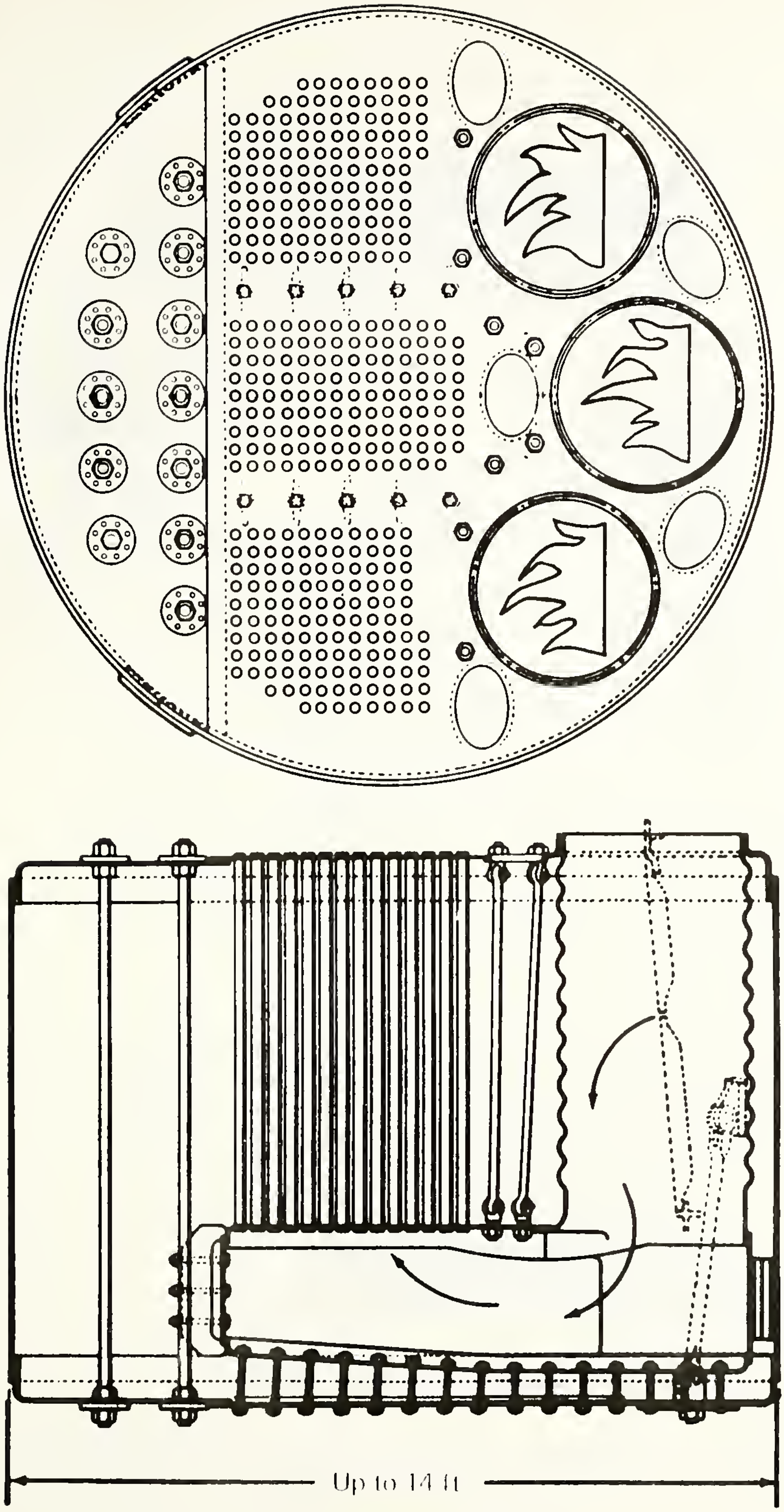
Coal is a natural choice for many reasons. Its use is growing rapidly in electric power production. In 1976 there were fifty-four fossil-fired central power stations

under construction, of which only four were not designed exclusively for coal. Of these four, one was a combined residual oil-fired plant. All were old designs contracted for prior to 1973. The growth in the use of coal will produce a growth in coal technology. New fuels and use methods will be developed which could benefit the Navy.

The buget requested for the Fossil Energy Research Program, FY 1978, by the Energy Research and Development Administration (ERDA) is $657 million. This is a large increase from the $58 million FY 1973 buget. The largest percent of this requested amount is to be spent in coal related research.[1]

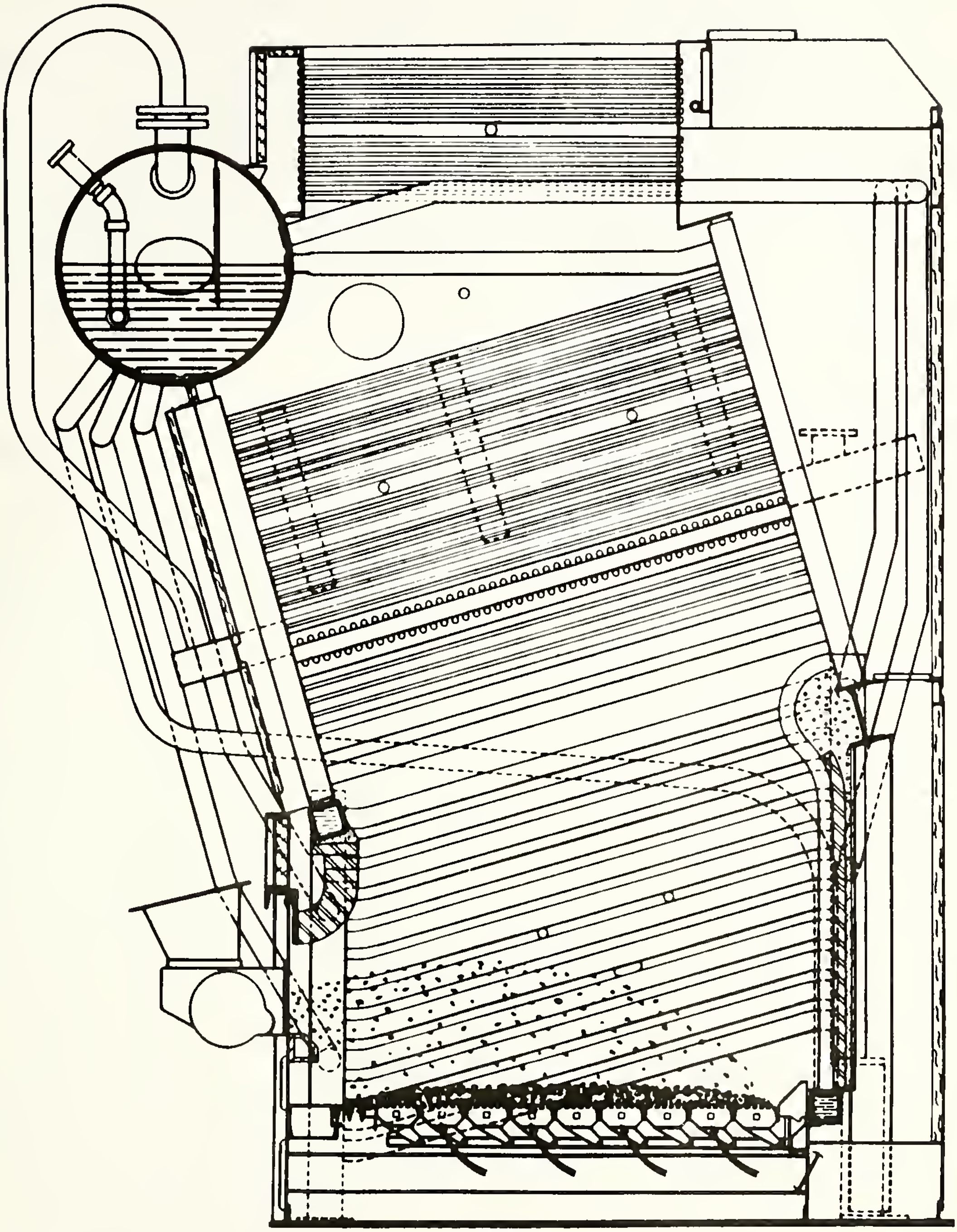
The use of coal as a marine fuel is not new, it is just forgotten. Prior to World War I, bituminous coal was the primary fuel for steamships. Early applications utilized fire tube boilers such as the Scotch Marine Boiler. (fig. 1) Its inefficiency, high weight to horsepower ratio, low capacity, poor response and safety considerations led to its passing.

Development of the sectional header type water tube boiler signaled an end to the fire tube boiler as a shipboard power boiler. (fig. 2) This design boiler was adaptable to either spreader or underfeed type stoker firing. Capacities were generally limited to less than 50,000 lbs. of steam per hour.



SCOTCH MARINE BOILER

figure 1



COAL FIRED HEADER BOILER

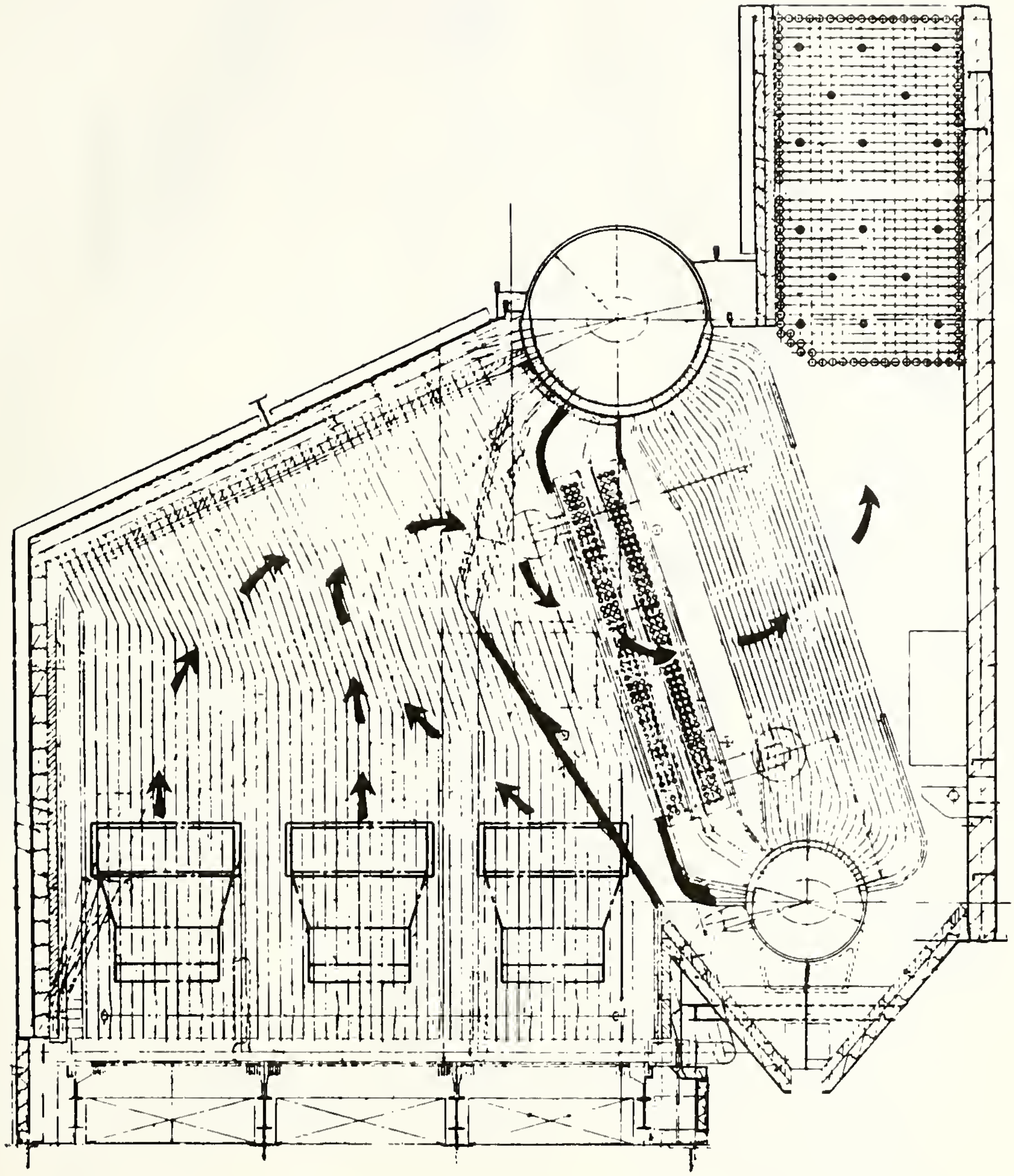
figure 2

The last surge of coal fired activity occurred in the 1950's on Great Lake vessels. At this time the trend was to two-drum boilers. (fig. 3) The two-durm boiler offered more flexibility in capacity, temperature and pressure. Furnace design was more adaptable to meeting grate loading and furnace volume requirements for stoker firing. With its use, operators were able to effectively utilize the relatively inexpensive, readily available coal fuels on the Lakes.

The last built ocean going vessel was the S.S. Iron Whyalla. This ship was built in 1954 for service between Newcastle and Whyalla, Australia. Coal was chosen as a fuel because of local availability and low cost. The ship operated for twelve years, coal fired. There was a completely new shipboard arrangement using Detroit Roto Stokers firing into a Detroit Roto Grate. (fig. 4) In 1966 the situation had so changed that the stokers were removed and the boilers were converted to oil firing only.[2,3]

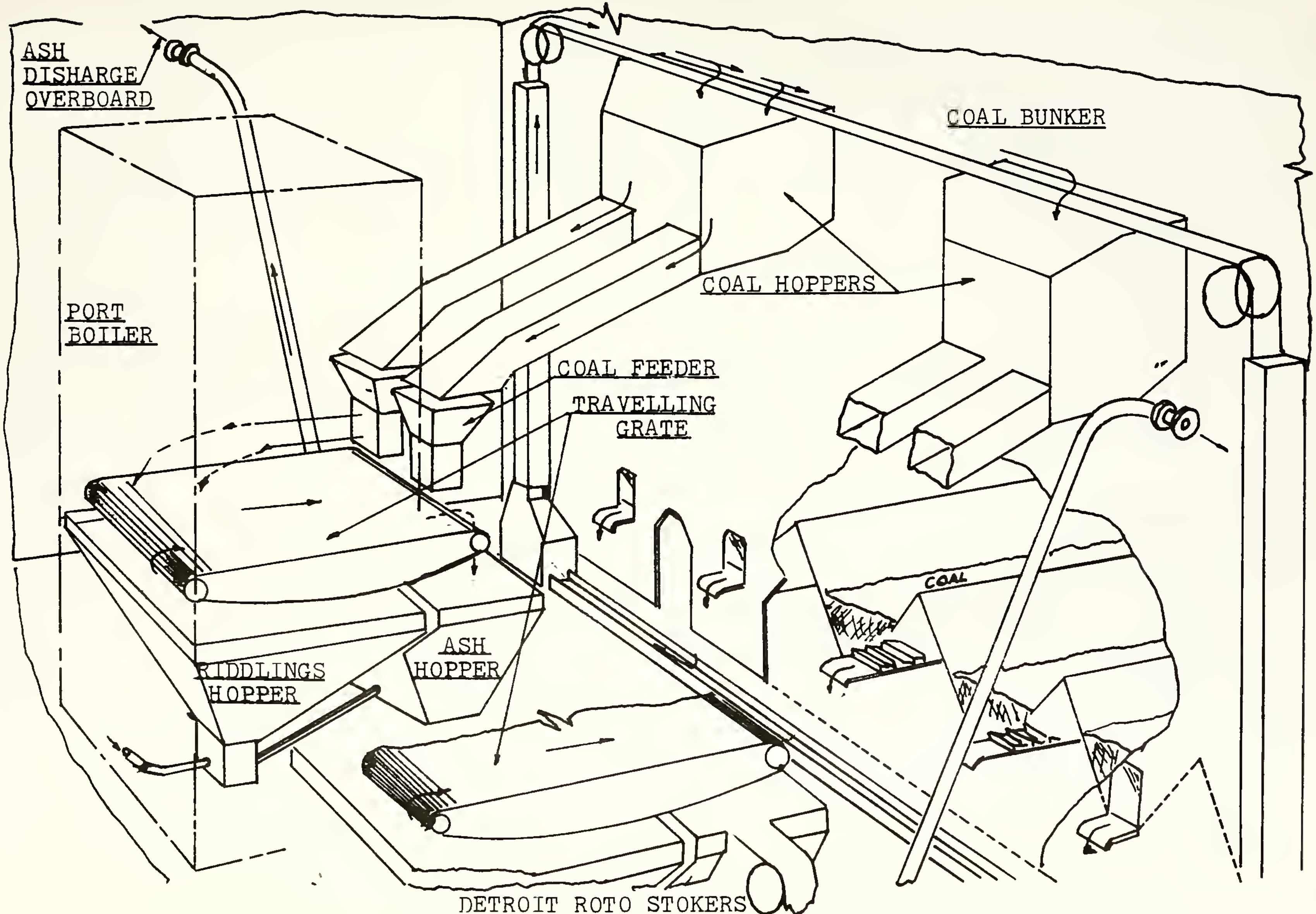
The advent of oil firing shortly prior to World War I brought a rapid end to coal firing on the high seas. Bunker C was available, cheap, and offered advantages in handling and bunkering.

Significant advances in the art of marine boiler design were now possible which would result in high capacity, high efficiency units designed for automatic operation.



COAL FIRED TWO DRUM BOILER

figure 3



DETROIT ROTO STOKERS
figure 4

The situation has again changed with oil becoming more scarce and expensive, and coal must once again be considered. This study discusses the many forms of coal as a fuel and the different combustor types available. The design impact and attendant problems of coal burning are explored.

If coal is to be used in the Navy, there exists a natural division for this study. The study is divided between the methods of coal use on present ships and the changes to the engineering plant for efficient use of coal on future ships. The inherent economics necessitate this division.

The cost of converting existing ships will prevent them from using energy efficient methods of burning coal such as fluidized bed combustion. Existing ships must be content with using coal derived fuels compatable with existing installations or coal-oil slurries.

II. WORLD ENERGY PROBLEM

A. Introduction

What is the world's energy problem? It is not supply. Estimated reserves would provide over a thousand year's supply of energy at today's consumption rate. This estimate excludes the fast breeder reactor program, which if successful, will add significantly to the world's total energy supply. Also excluded in this estimate are the low grade forms of energy such as wind, tidal and solar. Even oil, with a present consumption rate of 45 million barrels per day, (MBD) estimated reserves of 2,000 billion barrels would provide more than one hundred years' supply. But the assurance provided by these numbers is dispelled by the memory of the 1973 gas lines and the increased in the costs of electricity and heat.

One facet of the problem is the supply versus demand mismatch. It is of little use to provide a homeowner with coal when he has an oil furnace, even if the energy stored in the coal is equivalent to the oil he ordered. It is therefore meaningless to take comfort in the fact that there are over a thousand years worth of energy reserves, if action is not taken to enable the user to use the form in which this energy is found.

The second and more important facet of the world energy problem relates to petroleum. The world now consumes energy at a rate of approximately 120 million barrels a day oil equivalent (MBDOE), with oil supplying 60 MBDOE. Oil as a fuel has experienced tremendous growth in this century. Its contribution to the total energy consumed in the world, in 1900, was small. Energy from oil represented about one-thirtieth of the total energy consumed in the world. In importance it was equal to hydroelectric power, but provided only one-tenth the energy provided by wood. By 1950 it had surpassed all other forms of energy. From the 50's until 1973, oil experienced a 6% per annum growth. This is not surprising, considering the advantages of oil. It is an excellent fuel, easy to transport, store, burn, and even relatively easy to extract from the earth.

Because of oil's dominance in energy, its problems must be understood in order to understand the world's energy problem. To this end, four principal factors must be discussed. They include known reserves, the rate at which new discoveries or improved production techniques will add to them, the level of oil demand, and the rate of production that the OPEC countries might allow.

B. Oil

A misconception about oil is that it is found in vast underground pools, and once discovered, these pools may be pumped dry with relative ease. This is not so. Oil is found trapped in the small spaces between individual rock grains, rather like water in a sponge. As oil formed it seeped through porous rock until it was captured by impervious rock. Under this impervious layer (called cap rock if it is in the form of a dome) fluids, mainly water but often including oil, gradually accumulate. The oil finds its way to the top, due to its specific gravity. This constitutes an oil field or reservior. Gas also is commonly found in the reservoir, above the oil. This is illustrated in figure 5.

1. Petroleum terminology. If a well is drilled into an oil-bearing structure, the natural pressure in the reservoir forces oil into the well. Oil produced in this way varies from field to field. Factors such as viscosity of the oil and porosity of the rock are known to affect recovery by this method. Overall primary production accounts for less than 25% of the oil in place.

Other methods are used to improve well yield. Recovery

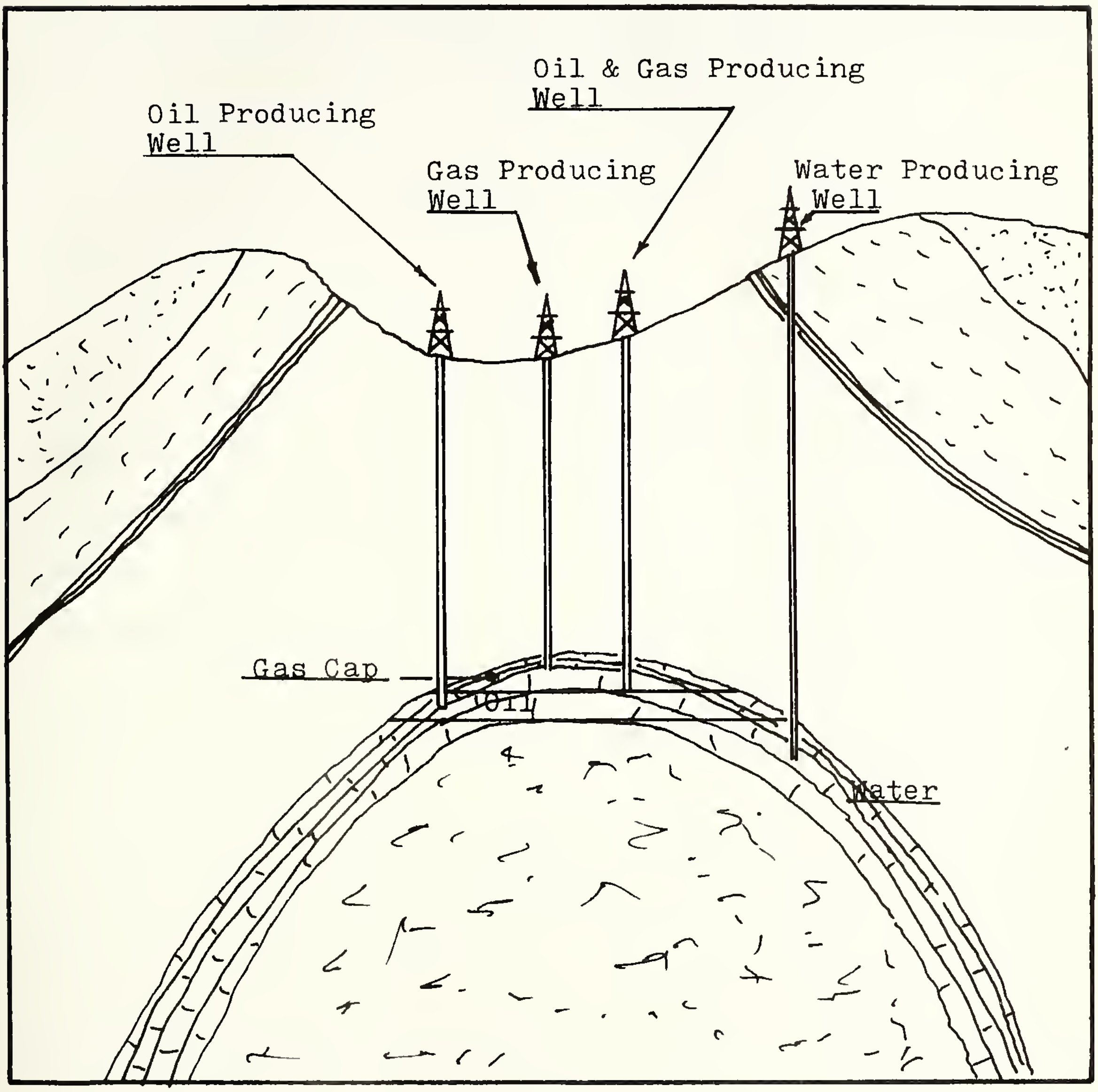

Oil & Gas Producing Well
Oil Producing Well
Gas Producing Well
Water Producing Well
Gas Cap
Oil
Water

figure 5

can be inhanced by pumping water or gas into the reservoir to increase or maintain the reservoir pressure. The techniques are known as secondary recovery. Gains in recovery using such techniques vary widely in practice. In the United States secondary recovery is mainly responsible for increasing recovery from 25% of the oil in place in the 1940's, to about 32% by 1975.

Another method of improving recovery rates from oil fields is to lower the viscosity of oil by heating it with injected steam, or by injecting chemicals to dilute the oil. This is known as tertiary recovery. Its use is presently limited because of its relative high cost. Additionally, because the method employs the injection of energy in the form of heat or chemicals, this causes a reduction in the net energy recovered in the oil, by the amount used in the heat or chemicals.

Two other terms that require definition are proven reserves and ultimately recoverable reserves of oil. Proven reserves of oil are defined as recoverable oil from known stores with present technology and prices. Therefore proven reserves include potential production based on the use of secondary and tertiary techniques, in addition to primary recovery. Some additional recovery techniques are also responsible for variations in proven reserve amounts when no new oil fields are found.

Ultimately recoverable oil reserves are an estimate of how much oil will be eventually produced. This is an estimate of new discoveries, plus an allowance for enhanced recovery.

C. <u>Oil supply</u>

To understand the oil shortage problem, supply must be considered. Estimates of the total World's ultimately recoverable reserves of crude oil have changed with time. The estimates have ranged from a low of 400 billion barrels in 1946, to the present 2,000 billion barrels. See table I. Since 1960, geologists have tended to converge to a figure of around 2,000 billion barrels. This would easily provide over one hundred years' supply at the present consumption rate, but the figures must be placed in their proper prospective by the consideration of some relevant facts. 1. Twenty five percent of the ultimately recoverable reserves have already been consumed. 2. Today's consumption rate will not be that of tomorrow. An accelerated growth in consumption is certain. 3. The reserve estimates include deep sea areas and the Antarctica, where the high cost of bringing the oil to the surface may preclude their exploitation.

Table I.

Estimates of Total World Ultimately Recoverable Reserves of Crude Oil For Conventional Sources

Year	Source	Billion barrels
1942	Pratt, Weeks & Stebinger	600
1946	Duce	400
1946	Pogue	555
1948	Weeks	610
1949	Levorsen	1500
1949	Weeks	1010
1953	Mac Naughton	1000
1956	Hubbert	1250
1958	Weeks	1500
1959	Weeks	2000
1965	Hendricks (USGS)	2480
1967	Ryman (Esso)	2090
1968	Shell	1800
1968	Weeks	2200
1969	Hubbert	1350 - 2100
1970	Moody (Mobil)	1800
1971	Warman (BP)	1200 - 2000
1971	Weeks	2290
1975	Moody & Geiger	2000

Source: Reference 4, page 115

1. <u>Reserve to production ratio.</u> Since oil can only be produced from fields that have been discovered and for which production facilities have been installed, it is in this framework that production limits must be found. Oil production is based upon proven reserves, the rate at which they are added to, and on the rate at which production facilities are developed. The importance of ultimately recoverable reserves is that they determine how long a rate of additions to reserves can be maintained.

Each field has a potential production rate which depends on the size of the field, its geological characteristics, and its installed facilities. Governmental control on production may also be important. Collectively, these factors set the upper limit on the annual production from an oil field.

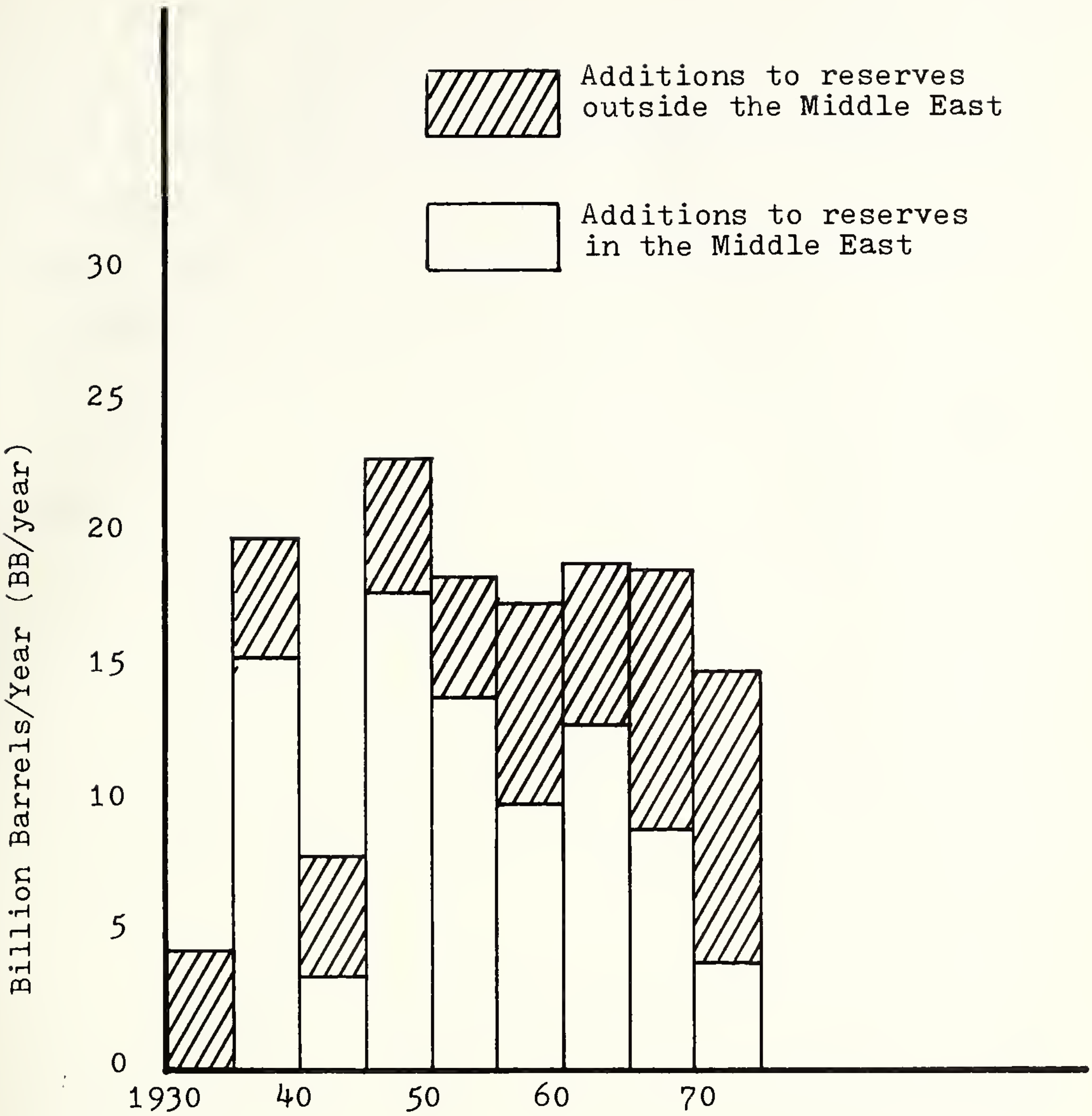
There are physical limits on the rate by which a field can be pumped. Primary recovery relies on natural pressure within the reservoir, and the maximum yield is obtained by releasing the pressure gradually. In practice this means that producing more than 10% of the recoverable reserves in one year will reduce the amount of eventually recovered oil. If all oil fields produced at this rate, the worlds reserve to production ratio (R/P) would be 10 to 1. Since new fields are still being developed and their reserves are included before they are producing at capacity, the worlds

R/P ratio is closer to 15 to 1. As discoveries decline, the R/P ratio may decrease toward 10 to 1.

The importance of these ratios is that they point out the fact that the rate in which oil can be produced is of much greater importance than the estimated total reserve. The shortage in petroleum will occur when the world's demand rate exceeds the rate of supply. This will be long before the reserves are exhausted.

2. <u>Proven reserves</u>. The next factor to be considered in the oil supply equation is the remaining proven reserves. These, coupled with the R/P ratio, provide the potential supply limit for oil. The magnitude of the world's remaining proven reserves is a dynamic number. The remaining proven reserve of oil changes with the addition of new proven reserves, refinements of estimates of existing reserves, and subtraction of usage. It is generally accepted that at the present time the world's remaining proven reserves of oil stand at around 600 billion barrels. Of this amount approximately 500 billion barrels are available to the world outside communist areas (WOCA). Eighty percent of this amount is contained in the OPEC countries.

To predict additions to proven reserves, the history of oil discovery rates in the WOCA will be used to set bounds for addition rates. From figure 6 an upper bound



OIL DISCOVERY RATE IN WOCA FROM 1930

(FIVE YEAR AVERAGE OBTAINED BY BACKDATING DISCOVERIES TO YEAR OF FIELD DISCOVERY)

Source: Exxon Press Briefing, World Energy Outlook, Dec.7,1975

figure 6

of 20 BB/yr. and a lower bound of 10 BB/yr. will be chosen. The choice of 20 BB/yr. is obvious from the figure. The lower bound is based on the belief that no more large oil finds like the ones in the Middle East are likely, and the present estimates of the proven reserves in that area are accurate and not likely to be refined upward.

At the present time actual production is less than the potential supply, based upon proven reserves. Production is determined by demand. As world oil demand continues to increase, there will be a point in time when demand will exceed supply and increasingly may serve to eliminate marginal users. The world price of oil at this point could reach unimagined heights. The belief that this point might not be that distant is one of the factors that prompted the writing of this paper.

3. Demand. In the years from 1960 until 1973 the growth in oil usage was 6.2% per year, compared to a WOCA economic growth of 5% per year. The oil embargo of 1973 slowed world growth to 4% per annum, with growth in oil demand slowing to 0.5% per year. Most of the decrease in demand was due to governmental controls and conservation measures, rather than a movement away from oil use. Oil usage is again on the rise, having exhausted the reserve provided by the pre-1973 oil usage inefficiencies. It is

doubtful that it will reach its former growth rate, but it is certain that it will not remain as low as it is at the present time. Its growth will probably be somewhat below the world's economic growth.

4. <u>Supply verses demand scenario</u>. Remaining proven reserves, additions to proven reserves, economic growth and the growth in oil usage are factors which must be considered to solve the supply verses demand oil problem. Each factor has been discussed independently but their effect on the supply verses demand problem requires that they be considered collectively. Because of the uncertainties of the estimated values of each factor and the interdependence between the factors, a scenario type approach is required to obtain conclusions about the problem.

The approach used in this study was to determine at what point in time demand would exceed potential supply. This point will be refered to as the "break point" in the following discussion. The break point is important because when it is reached, the suppliers of oil must employ some means of determining who will recieve oil. The mechanism of determination can be political or price, or a combination of both. The uncertainty presented by this situation is the reason the point is so important. It can occur long before oil is exhausted but its effect on those

who are unable to obtain needed supplies of oil will be the same.

To determine the break point, assumptions about remaining proven reserves, additions to reserves, oil demand rate and ultimately recoverable reserves have been made.

The assumptions have been chosen with sufficient range to cover most conceivable combinations of factors. It was assumed that supply equals demand as long as potential supply is greater than demand.

a. <u>Physical limits only scenario</u>. The first set of data points generated (as illustrated in figure 7) assumed no controls on production other than the afore mentioned physical limits. This presents a very optimistic picture of the problem.

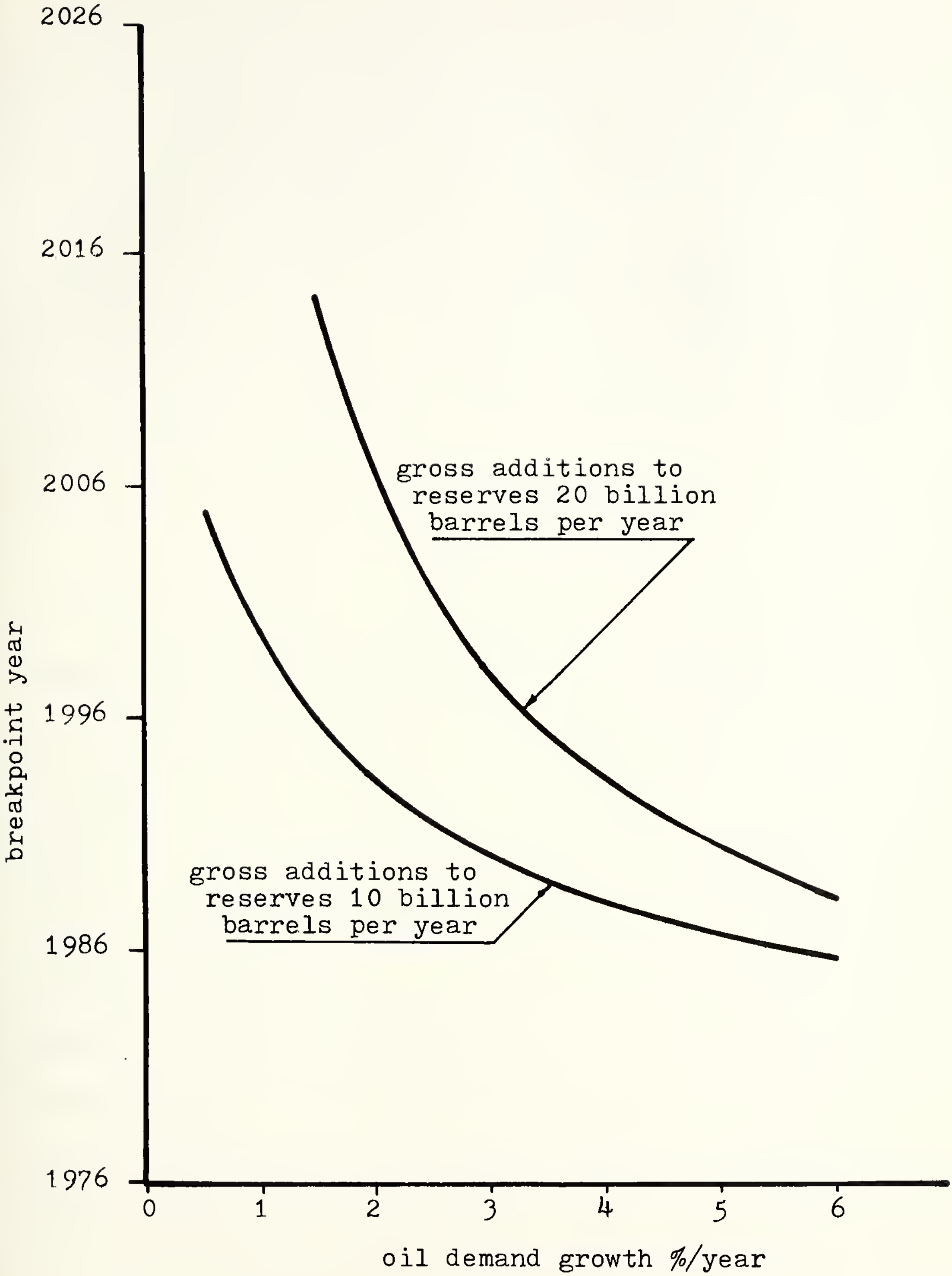
Table II.

Assumptions for supply verses demand breakpoint profile for WOCA.

1. Proven reserves at end of 1976 - 515 billion barrels
2. Oil demand rate in 1977 - 16.5 billion barrels / year
3. Oil demand growth range - 0.5% to 6%
4. Gross additions to reserves range - 10 to 20 BB/yr.
5. Limiting R/P ratio - 15 to 1

Figure 7 shows results that indicate with a growth in oil consumption of 3% per annum that the breakpoint will occur between the years 1990 and 1997. These numbers are conservative since a growth in additions to reserves of 20 billion barrels per year exceeds all past years' performance with the exception of the period from 1945 to 1950, as is shown in figure 6. If world economic growth increased to 5% per annum the expectant growth in oil consumption will be 4% per annum, and that would place the breakpoints between 1988 and 1993. The final and most optimistic of the assumptions made in developing figure 7 is that oil producers would be willing to allow their fields to produce to their physical limits.

b. Governmental control scenario. Since 80% of the WOCA remaining reserves are OPEC countries, they hold the key to the real R/P ratio. If OPEC decides to restrict production the breakpoint years will occur much earlier than those predicted by a physical limit scenario. At the start of 1976 the OPEC countries supported the supply of oil with a R/P ratio of 45 to 1. This ratio allowed OPEC to supply 10 BB/yr. of the required 16.5 BB/yr. WOCA demand. While OPEC maintained a R/P ratio of 45 to 1 the remaining WOCA suppliers were forced to a R/P ratio close to the 15 to 1 physical limit.



BREAKPOINT YEAR VERSES OIL DEMAND GROWTH

figure 7

Individual OPEC countries may be unwilling to see oil production reach the maximum theoretical level because of a desire to extend the life of their oil reserves. The present glut of oil dollars flowing into OPEC countries leaves problems for these countries in finding investment opportunities for this money. In Petroleum Intelligence Weekly of 2 February 1976, possible production limits were announced by some OPEC countries. These limits are illustrated in Table III.

Table III

Possible Production Limits Announced by Governments (BB/yr.)

Venezuela	.80
Equador	.073
Libya	.730
Qatar	.183
United Arab Emirates	.657
Kuwait	.730
Saudi Arabia	3.102
Total	6.278

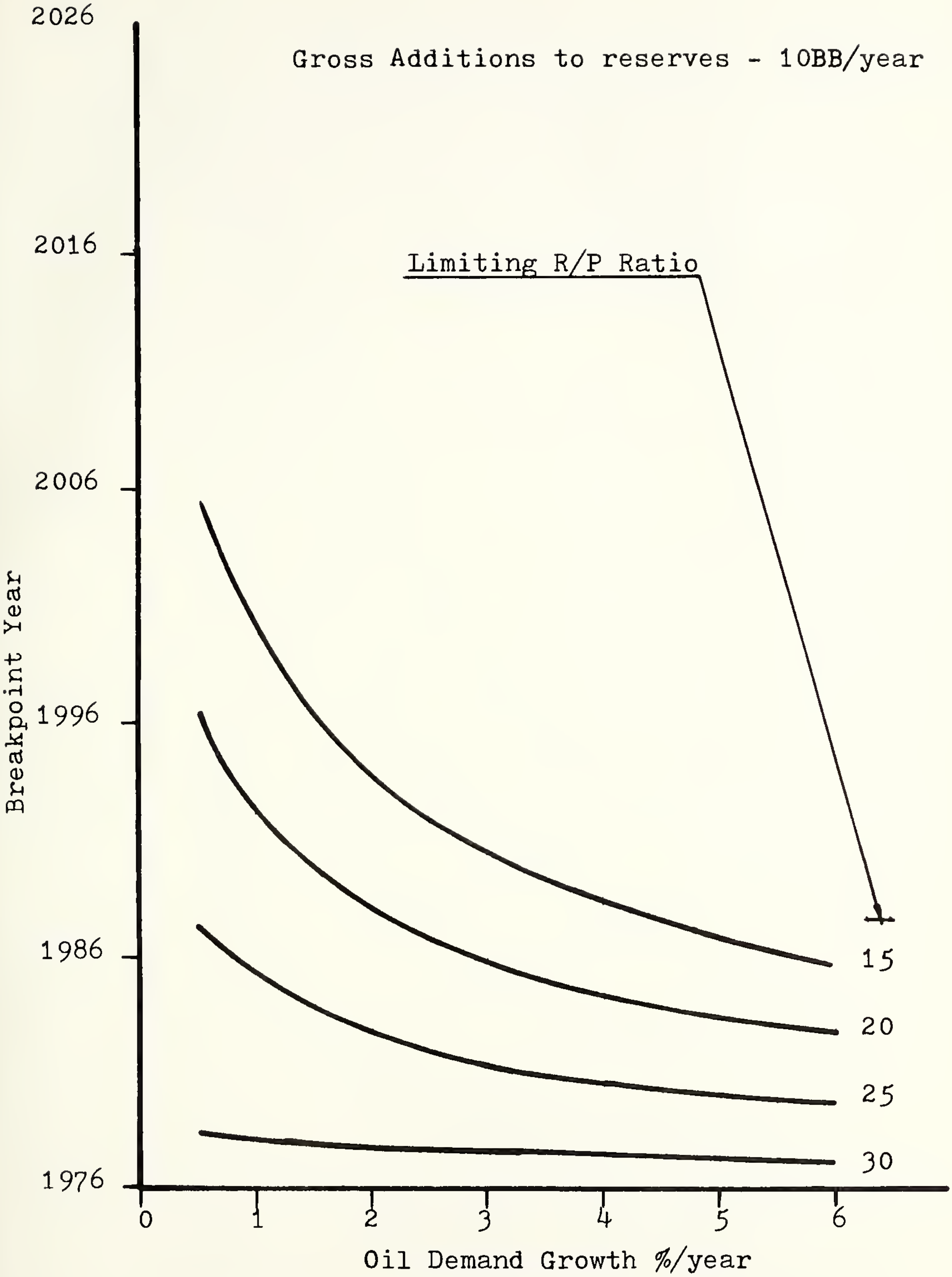
Since it is uncertain what the OPEC countries will do, their possible impact can be best illustrated by varying the R/P ratio. Figures 8 and 9 have been developed using the assumptions of Table IV.

Table IV.

Assumptions for Supply Versus Demand Breakpoint Profile For WOCA, With Governmental Control

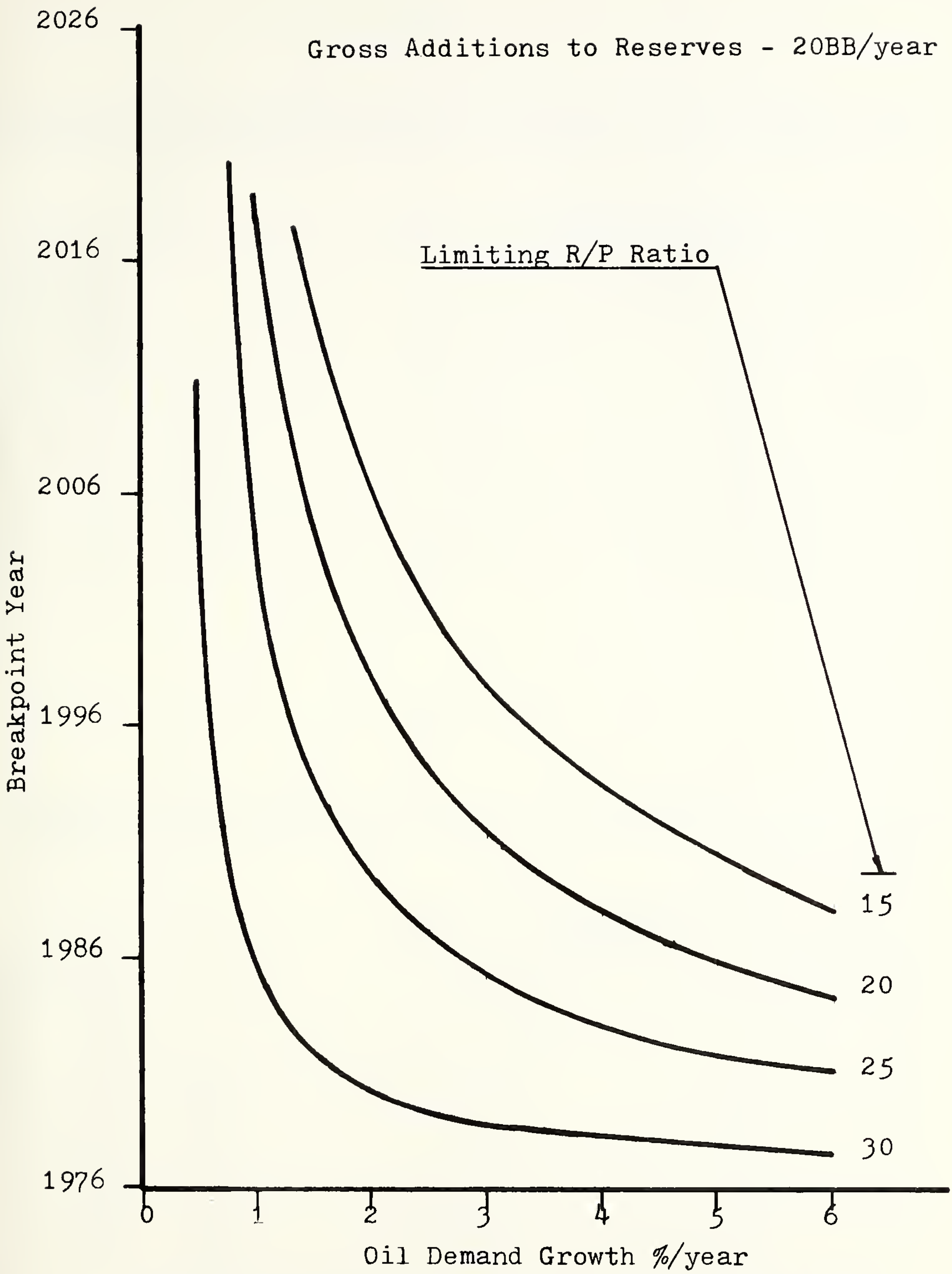
1.	Proven reserves at end of 1976	515 BB
2.	Oil demand rate in 1977	16.5 BB/yr.
3.	Oil demand growth range	0.5% to 6%
4.	Gross additions to reserves	10 BB/yr. (fig. 8)
		20 BB/yr. (fig. 9)
5.	Limiting R/P ratio range	15-1 to 30-1

Figures 8 and 9 graphically illustrate the effects of increasing the R/P ratio. As the ratios are increased, the year of the breakpoint moves closer to the present. Tables V. and VI. serve to illustrate this effect.



BREAKPOINT YEAR VERSES OIL DEMAND GROWTH WITH GOVERNMENTAL CONTROL

figure 8



BREAKPOINT YEAR VERSES OIL DEMAND GROWTH WITH GOVERNMENTAL CONTROL

figure 9

Table V.

Breakpoint Versus R/P Ratio For Growth In Oil Demand of 3%

R/P		Breakpoint Year	
		Gross Additions to Reserves	
R		10 BB/yr.	20 BB/yr.
A	15-1	1990	1997
T	20-1	1985	1991
I	25-1	1981	1985
O	30-1	1977	1978

Table VI.

Breakpoint Versus R/P Ratio For Growth In Oil Demand of 4%

R/P		Breakpoint Year	
		Gross Additions to Reserves	
R		10 BB/yr.	20 BB/yr.
A	15-1	1988	1993
T	20-1	1984	1987
I	25-1	1980	1983
O	30-1	1977	1978

The uncertainty of each variable in the supply versus demand problem and the complex interdependence of the variables make accurate prediction of the breakpoint impossible. Even a more detailed study such as that performed by the Workshop on Alternative Energy Strategies (summarized in reference 4) pales at the task of accurate prediction. Accurate prediction is not the purpose of studies such as these. The purpose is to analyze the problem in detail, to determine the magnitude of the problem and hopefully highlight the areas where solutions exist. It is important to realize that the oil problem is real and without major changes in the world's energy appetite the breakpoint years are soon coming. With petroleum, the supply versus demand problem is demand controlled. Supply is limited physically, both in the rate of removal from the ground and the rate at which present supplies may be added to.

It is clear that the problem could be lessened by the world switching to other forms of energy. Petroleum should be reserved for uses where other forms of energy cannot be substituted. The world's largest consumer of energy is the United States. It is fortunate that this country is also rich in other energy forms, and in the necessary technology to use them.

III. The United States' Energy Problem

The U.S. energy problem is basically the same as the world's energy problem in regard to petroleum. Where magnitude is concerned the problem is markedly different. The U.S. population represents only 7% of the WOCA total population, but is responsible for 40% of the total petroleum consumed.

The U.S. was self-sufficient in oil in 1950. It became a net importer in 1970, and by the year 1976 it was importing 40% of its consumption requirements of 17.4 million barrels per day. The import requirement would have been higher if a 0.4% stock drawdown had not occured. By the winter months of 1977 oil imports reached 50% of consumption. The increasing dependence on imported oil cost the U.S. $35 billion in 1976, and even more in 1977. This outflow of money further aggravated inflation and slowed economic recovery.

A simple solution to the U.S. oil problem would be to find more oil, but this solution is not probalistic. At the present consumption rate of 18 MBD, a producing proven reserve base of 66 BB would be required if a R/P ratio of 10 to 1 is assumed. The present U.S. proven reserve is approximately 40 BB, so there exists a short-

fall of 26 BB in proven reserve size. The size of the Alaskan oil find was 10 BB in proven reserve addition. Therefore the U.S. would require finds equal to 2.6 times the Alaskan oil discovery to meet today's needs. Based upon the history of oil discovery, the probability of any oil field being greater than 10 BB is small. Of the 30,000 fields already discovered only 15 have been 10 BB or larger.[4] This yields a probability of 0.0005. Even this small number is conservative if it is realized that each discovery of oil came from a finite set of oil pockets and any find is a mutually exclusive event with respect to the set. It is therefore unlikely that the solution to the U.S. petroleum problem is in increased exploration for oil.

The answer to the problem must lie in substitution of more abundant forms of energy possessed by the U.S. Those forms which are adaptable to ship propulsion are coal, shale oil and nuclear power.

This discussion will not include nuclear power to any great extent. The U.S. Navy already has a workable nuclear program and the future plans for most large ships and submarines include a nuclear option. It is doubtful that any plan for an all nuclear navy would succeed at this time, for several reasons. First, the economics of nuclear power must be considered. The Royal Navy has concluded

that to build a nuclear powered ship which is competitive with an oil powered ship, it must be at least 20,000 tonnes.[5] This was based on 1974 oil cost figures, versus nuclear fuel cost. The breakpoint in size naturally will vary as the cost of oil varies with respect to nuclear fuel cost. It is clear that to justify nuclear propulsion on economics solely, will limit the discussion to very large ships. There are applications for nuclear power where no other present means of propulsion are satisfactory, namely in submarines. There are a large number of remaining ships that require some means of powering. To choose nuclear power for propulsion would not be realistic even disregarding the economics. While the public might accept a few nuclear powered ships, because of their inherent advantages for specific missions, they would not be willing to accept wholesale numbers of nuclear powered vessels. The arguments against nuclear electric facilities would also apply to ships. The unique character of nuclear energy as a source of radioactivity and its potential for destruction has been the main argument slowing the growth of the nuclear power industry. Even the impressive safety record of the industry has done little to diminish the fears of the general public.

Finially, the Navy finds it diffucult to find and train

enough qualified personel now. To greatly increase the nuclear program would present a very difficult manning problem. It would be impossible to man many more nuclear powered ships and still maintain the present high stand - ards and safety record.

IV. The Concern of The U.S. Navy

A. Introduction

The Navy is continuing to design ships which consume oil in an era of declining oil resources. In one respect this is logical since the Navy is a small user of petroleum compared to the nation as a whole. The Navy is a follower in the development of hydrocarbon fuels. The Navy in isolation could not possibly afford to develop a new fuel route.

There is also a false security in knowing that the National Security will afford the Navy some priority in obtaining needed supplies of oil.

The fallacy of the preceeding logic lies in the knowledge that new fuel routes are already being developed. The Navy must be aware of the developing fuel trends, and design to utilize these fuels where possible.

Cost of fuel must also be a factor. When demand for oil exceeds supply the price of oil will only be limited by the cost of the next cheapest subsitute. This subsitute will be synthetic oil from coal or refined shale oil. The fleet now consumes oil at a rate of between 30 and 40 million barrels per year. A doubling of the present cost of fuel could increase the Navy's fuel buget by as much as

eighty million dollars.

B. Shale oil versus coal

Of the present new fuel routes that are of interest to ship designers, shale oil and coal are the most likely replacement sources for oil. Both sources show promise as a replacement fuel. Thorough investigation must come before any judgement as to which fuel shows the greater promise.

1. Shale oil. Oil shale is a finely textured sedimentary rock, containing the solid, largely insoluble organic material kerogen, yielding a raw oil suitable for use as a refinery feedstock. The principal deposits of oil shale are found in Colorado, Utah and Wyoming. Present estimates place the shale oil deposits at two trillion barrels of oil. Of this vast reserve, only a small percentage is sufficiently accessible and concentrated enough to be commercially interesting. Commercially interesting concentrations are presently limited to seams of thicknesses of over 30 feet, yielding at least 30 gallons of oil per ton of rock. Reference 4 states that only about 6% of the known reserves meet this requirement.

Table VII presents a different breakdown of oil shale reserves derived mainly from the 1965 gallons per ton

estimates.

Table VII.

U.S. Oil Shale Resources, 1972

(BB - by oil yield)

Oil Shale Yield	Identified Deposits	Undiscovered Resources
25 to 100 gallons per ton	418	900
10 to 25 gallons per ton	1,600	25,000
5 to 10 gallons per ton	2,200	138,000

Later information presented by the U.S. Geological Survey estimates known reserves with yields of 15 gallons or more per ton at 1,000 billion barrels, and deposits yielding greater than 30 gallons per ton at 209 billion barrels. It is clear that while there is a large variation in estimates of reserve size, there is general agreement that shale is abundant.

The extracted shale oil is relatively light compared to bunker C in weight. A typical analysis is shown in Table VIII. Nitrogen content is high, making the oil undesirable for stationary boilers without further processing.

The low pour point necessitates some heating to enable the oil to be pumped. Heating requirements for combustion are low, generally in the range on 140° F. to 150° F.

Table VIII.

Typical Shale Oil Analysis[6]

Ultimate Analysis	Percentage, weight
Carbon	86.0
Hydrogen	11.0
Sulphur	0.73
Nitrogen	1.12
Ash	0.016
Oxygen (by difference)	1.134

Heating value: 18,340 BTU/16

Specific gravity @ 100° F. - 0.9503

Pour point: 95° F.

Except for the percentages of Nitrogen and Oxygen, this analysis is similar to that of typical petroleum base fuels.

As shown in Table IX the characteristics of shale oil

are very similar to those of no. 5 and no. 6 fuel oils. Numbers 5 and 6 fuels can now be utilized in most existing marine power plants. Therefore the conversion to the use of shale oil should present minimal difficulties. A trial with shale oil was conducted aboard an ore carrier on the Great Lakes during May of 1975. No changes were made to either boiler or burners relative to normal bunker C firing. No operational difficulties or detrimental effects to combustion were noted. In fact it was possible to operate with about 3% reduction in excess air. For all practical purposes basic performance remained unchanged. This test was part of an evaluation program conducted by the U.S. Department of Defense.

Table IX.

Typical Analysis for Numbers 5 and 6 Fuel Oils

Ultimate Analysis	Number 5	Number 6
Carbon	86.5 - 89.2	86.5 - 90.2
Hydrogen	10.5 - 12.0	9.5 - 12.0
Sulphur	0.5 - 3.0	0.7 - 3.5
Nitrogen	-	-
Ash	0 - 0.1	0.01- 0.5
Oxygen	-	-

Table IX. (continued)

Typical Analysis For Numbers 5 & 6 Fuel Oils

Ultimate Analysis	Number 5	Number 6
Heating value BTU/16	18,100-19,020	17,410-18,990
Specific gravity at 100°F.	0.972-0.922	1.022-0.922
Pour point - °F.	-10 to +80	+15 to +85

a. Development of a shale-oil route. Based on physical characteristics alone, syncrude developed from shale oil would be an acceptable replacement fuel for marine use by the Navy. The problem with shale oil syncrude is quanity and not quality. In the 1940's small shale oil industries existed in Sweden, the United Kingdom and a few other countries, but low cost imported oil halted these industries. There now exists no commercial scale shale oil industry anywhere in the world.

As previously mentioned, the Navy cannot afford to develop a new fuel route and must depend upon supplies which are derived from a developed industry. The development of a shale oil fuel route can come from the commercial sector or a federally funded endevor, or a combination of both governmental and commercial funds.

Inflation has now increased the estimated cost of commercial plants beyond the range of usual industrial funding and the uncertainty about future oil prices, increases the investment risk. Reference 8 summarizes the problems and costs of developing a syncrude industry, including both coal and shale oil as feed stocks. The costs are enormous. In 1977 dollars the expendatures required by the year 2000 would approach 300 billion dollars. Even oil companies with their large resource base, view this number as staggering.

Disregarding the investment expense, what are the expected gains? Industrial decisions to deploy commercial scale synthetic liquid fuel plants must be made based on expected returns. A study performed by the Stanford Research Institute (Murray, 1971) indicated that syncrude produced from shale oil would have to sell for $3.20 per barrel to be profitable. This price was on a par with the crude oil price at this time and therefore presented no market advantage. This was also an estimate.[9] Present estimates place the production cost of syncrude of comparable quality to Arabial crudes at $9.00 to $15.00 per barrel for in situ recovery and $17.00 to $29.00 per barrel for surface retorting.[4] These are production cost estimates and the sales price would be higher when profit is included.

The uncertainty in the commercially economical price of syncrude, coupled with the uncertainty in the market price of energy with which syncrude must compete, seems to indicate that the large capital expenditure required to develop the industry is unlikely to come from private sources. The nation is caught in a catch-22 situation. The venture is too uneconomical to attract the necessary capital to develop the industry, but waiting until it becomes economical is useless. At this time there will be a shortfall between demand and supply and no syncrude industry will exist to fill the gap.

b. Federal subsidies. Federal subsidies for oil shale development appear necessary. If history is a teacher, the form of the federal subsidies will be confined to the research and development areas. The pace of the process whereby new technologies are put into commercial use and the decisions about the investments that make up that process, were left to the private sector. The energy problem is leading the United States to depart from this norm. Through the Energy Research and Development Administration the government is investing substantially in energy technology. However, the investment in shale oil research for 1978 is only 6.3% of the total buget.[1] This amounts to

41.5 million dollars, and seems hardly enough when it is considered in light of the billions of dollars required to develop the industry.

Reference 10 presents a more complete discussion of the relationship between the government and the private sector and their respective roles in developing a new energy route.

It seems unlikely that the development of shale oil will progress soon enough to be considered as a replacement fuel for marine power plants.

V. Coal - The Developing Fuel Route

A. Introduction

Coal has long been used in this country as an energy source. Coal use has exibited a curious growth pattern. From 1850 to 1900 its yearly consumption grew at a rate of 7% per annum. A switch to oil was evident in the growth rate of coal after this time with coal use remaining almost constant, with the exception of peaks occuring during World Wars I and II. The reason for the peaks during the war years is obvious, but the implication of subsituting coal for petroleum is more subtle. The consumers of energy in the raw form have always realized that there is a potential reserve of energy in coal, but because of the convience offered by petroleum this potential has remained essentially untapped. The oil embargo in October of 1973 has again brought coal to the fore. The difference between now and the war years is that coal is no longer being considered just a transient solution. The supplies of petroleum are running out and the gaps in energy demand require that other sources be tapped. Coal has the advantage over other potential replacement sources in that it is already an established industry.

Coal as a developing fuel route has an added push due

to the emphasis placed upon it by the federal government as a replacement fuel for petroleum. President Carter's 1977 energy policy gave a clear cut priority to coal production and to energy conservation. Subsitution of coal for oil in electric power utilities and industry was a stated objective. In mid-1977 it was forecast that total coal consumption would increase by 6.6% above the 1976 figure, to reach 700 million short tons.

The buget requested for the Fossil Energy Research Program, FY 1978, by ERDA is $657 million. Of this amount 68% (447.5 million) is slated for coal related endeavors. ERDA's buget in the area of coal research has increased seven fold since 1973. A more complete breakdown showing the areas in which ERDA's money is to be spent is provided in Table X. The table shows that the great majority of the money is being spent on coal.

There are also many privately funded endeavors in the area of coal utilization. During 1977 Stone and Webster Engineering Corporation performed an economic and technical feasibility study on producing and firing clean coal liquids and solids in power generation units.[12] This study was performed for the Northeast Coal Utilization Program, (NECUP) whose members include Boston Edison, Long Island Lighting Company, New England Gas and Electric Association

Table X.

Fossil Energy Development FY 73 to FY 78 ERDA Buget Authority[1]

Program/Subprogram	FY 1973	FY 1974	FY 1975	FY 1976	FY 1977*	FY 1978*
Coal						
Liquefaction	$10.4	$45.5	$94.7	$97.9	$73.0	$107.0
High Btu Gasification	25.2	33.3	59.8	53.4	44.0	51.2
Low Btu Gasification	3.0	22.1	50.0	24.5	33.0	73.9
Advanced Power Systems	0	0	4.1	10.0	22.5	25.5
Direct Combustion	.5	15.5	35.9	46.1	51.9	53.2
Adv. Research & Tech. Dev.	0	7.4	23.3	35.4	37.1	40.0
Demonstration Plants	0	0	0	27.9	53.0	50.9
Magnetohydrodynamics	0	7.5	14.3	33.5	35.0	45.8
Other	13.7	2.6	0	0	0	0
Petroleum	3.1	8.7	28.2	43.2	42.9	76.1
Oil Shale & In Situ Technology (includes coal)	2.5	3.2	11.2	21.1	30.5	39.0
Total Operating Expenses	58.4	140.6	321.5	393.0	422.9	552.6
Capital Equip. & Oper. Exp.	-	-	13.3	33.5	60.2	94.3
Fossil Energy Total	-	-	334.8	426.5	483.1	656.9

* Estimate

Service Corporation, New England Power Service Company, and Electric Power Research Institute. This study was prompted by an earlier study by Stone and Webster, which indicated a need to examine more closely the alternatives to using imported petroleum.

The NECUP study concluded that it will be technically feasible to produce coal liquids by 1985 which would be competitive in delivered price with imported petroleum.

Another example of privately funded research is an ongoing study by Fluor for Empire State Electric Energy Research Corporation. This study is on front end coal utilization for power plants.

It can be concluded that coal is a future fuel and much money is being spent to develop its use. The unanswered question is, How can the Navy utilize this knowledge to design future ships? A synthetic fuel derived from coal could be used with minimal design impact, but fuel cost is sure to be equal to that of petroleum. The use of advanced concepts such as fluidized bed combustors, would allow the utilization of elemental coal, but at the cost of significant design changes. The remainder of this thesis will explore the impact of the coal fuel route on the design of naval vessels.

B. The resource base

The overriding factor in favor of coal as a replacement fuel for petroleum is its abundance. The world possesses vast reserves of coal, far in excess of those of any other fossil fuel. There are sufficient reserves to support massive development of coal well into the next century. Like petroleum, the estimates of the quanity of coal available vary with the organization performing the study. Estimates in petroleum, which are made and published by the major oil companies rather than by the governments involved, tend to be highly variant depending upon commercial demand. Coal, on the other hand, tends to have a more stable base and estimates are less dependent upon demand. Even so there are large differences in estimated amounts. The World Energy Conference's Survey of Energy Resources, 1974 estimates the world's total resources of all ranks of coal to be about 15,000 billion metric tons, with known reserves of 8,000 billion tons.[13] Of this amount Darmstadter notes:

> If energy consumption from all fuel were to grow at the annual 5% rate....cummulative energy requirements to the end of the century....might amount to 400 billion tons of coal equivalent. Not only could the estimated 4.3 trillion tons of estimated recoverable coal resources meet this entire growth of energy demand, but in the year 2000, at the then prevailing rates of total energy consumption, enough coal would be left in the ground to meet the entire bill for a century and a half beyond.[14]

Proven coal reserves expressed in terms of oil equivalent therefore are in the range of 3,000 to 9,000 billion barrels. Compared with the (ultimately recoverable) estimates for petroleum of 2,000 billion barrels, the amount of energy abailable from coal is indeed large. In terms of proven reserves of oil versus coal, coal's advantage is 5 to 15 times that of oil, depending upon the source of the data.

These numbers should be very comforting to the United States. We are the world's greatest user of energy and soon will be importing fifty percent of our energy requirement. We also have large coal reserves. The largest reserves known are in the U.S.A., USSR and China. Of the world's known (measured) reserves, 30% are in the U.S. The U.S. portion of economically recoverable reserves is higher, at 34%.

The abundance of coal is in itself not the total answer to the U.S. energy problem. The coal industry will require tremendous growth to meet future demands. Large increases in coal production and use would have a profound impact on people's attitudes toward coal. It will require developing a new infrastructure and new technology for coal mining, processing, and use. Serious environmental issues related to extensive coal mining and coal burning must be

faced. The problems will be solved out of necessity if this country's energy appetite does not change.

Our present experience with coal, the money being spent on developing new coal technology, and the abundance of the resource, guarantee that coal will be a future fuel route. The Navy must then examine what is being done and decide what impact it will have on future ship designs.

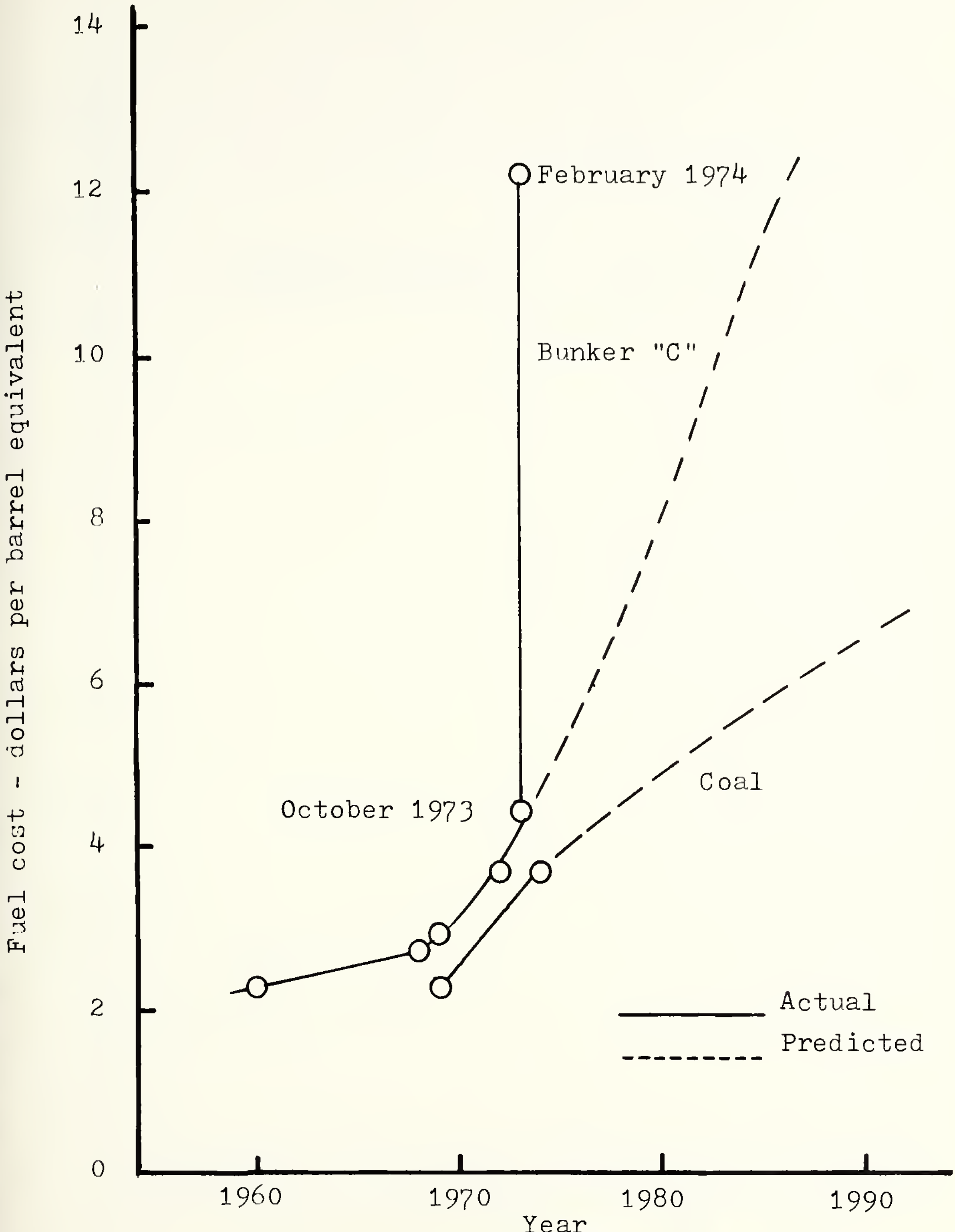
C. The cost advantage

Abundance alone is sufficient to insure coal's development as a future fuel. Coal has the added advantage over other fossil fuels in that it is less expensive on a cents/BTU basis. Prior to the October, 1973 fuel crisis this cost advantage was not of sufficient magnitude to promote industry wide utilization of coal as the primary fuel. Coal's inherent disadvantages, such as polluting combustion by-products, ash handling problems, more complex and expensive fuel handling systems and variations in quality of the fuel, erased most of the small cost advantage coal held over petroleum products. This was particularly true for marine use. Most modern naval combatants are volume limited and the additional 75% volume increase required for fuel stowage plus the increased fire room size to accommodate larger boilers and fuel feed systems, negated the small cost

advantage. The added problems of ash handling, cleanliness and fuel transfer at sea placed coal as a marine fuel even further in disfavor.

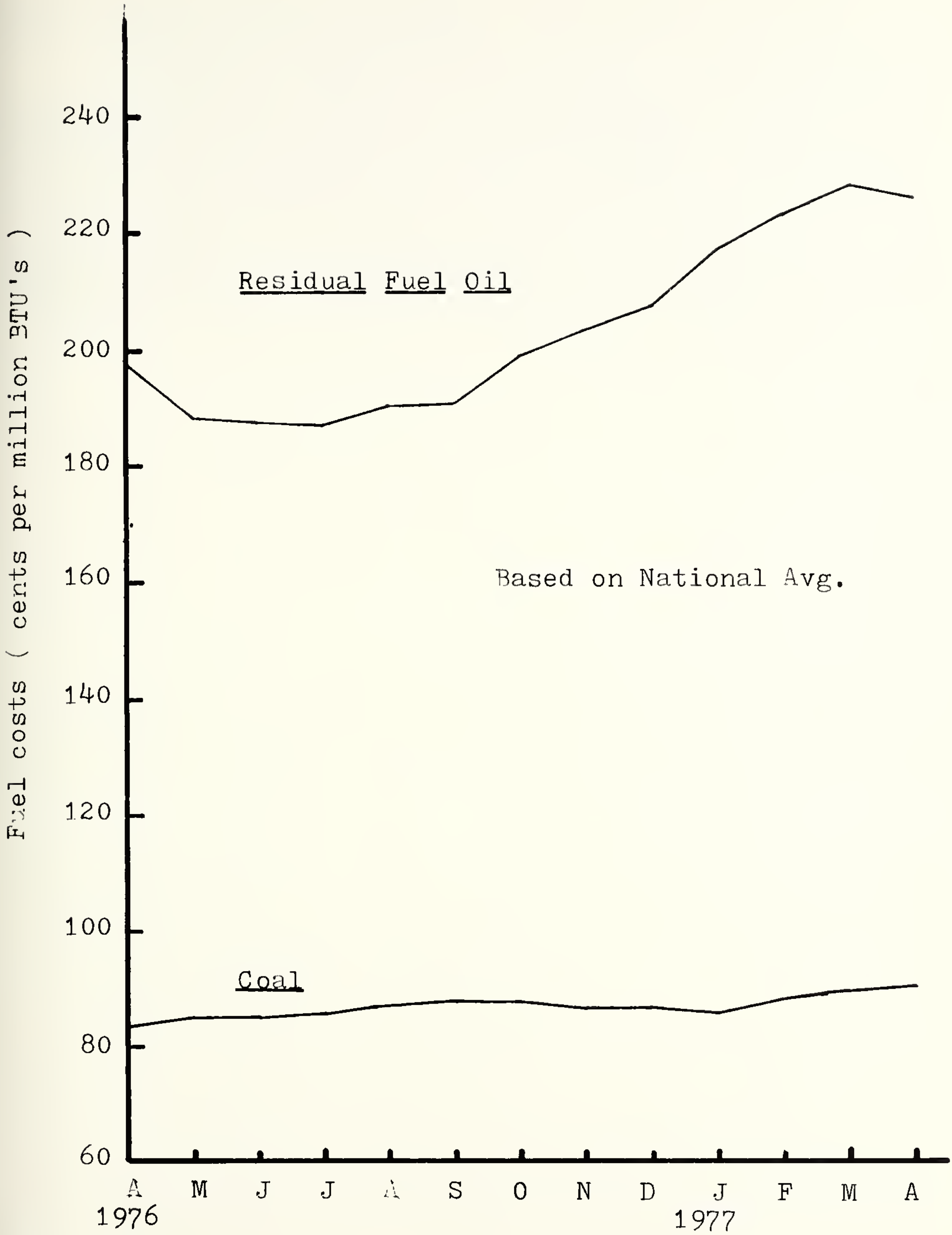
Figure 10 shows the trend in cost of oil versus coal prior to October of 1973. The dotted lines are the predicted trends in cost. The price has in fact risen faster than predicted, but the relationship between the price of coal with respect to oil has proven to be accurate. Coal cost tends to be about one half the cost of oil on a cents/BTU basis. Figure 11 shows this relationship, based upon national average figures for the period between April, 1976 to April, 1977.

The cost advantage of coal will not in itself be the determining factor in its acceptance as a naval fuel. Modern methods must be developed to handle coal at sea. The modern Navy would not accept open bunkering of coal or spreading stokers or traveling grate feeding. The system's response would be too slow for a modern combatant. There would also be a problem with cleanliness and the additional labor required to maintain spaces to present standards. For current acceptance for naval vessels the systems developed to burn solid fuel must be a generation ahead of what has been used in the past. The most likely candidates would either be some type of pulverized coal firing unit



TRENDS IN SHIP PROPULSION FUEL COST[15]

figure 10



PRICE TREND FOR COAL AND RESIDUAL FUEL OIL[16]

figure 11

or a fluidized bed combustor.

If syncrude from coal is envisioned as the future Navy's fuel there will be no cost advantage. The cost of future liquid fuels derived from coal will at the least be on a par with petroleum fuels and probably they will be more expensive until petroleum supplies can no longer meet demand.

VI. The Combustion of Coal

A. Introduction

To understand the combustion of coal one must first understand how coal was formed and how it is classified.

As a discriptive noun the word coal covers a broad range of carbonaceous material formed from dead vegetation. The foundation of present reserves was laid about 300 million years ago in the swamp forests of the Carbonferous Age. At that time the mild climate on Earth encouraged vast growths of primitive trees and vegetation. When these plants died, they fell into the shallow water of the swamps. As the plant tissue lay submerged, portions of its molecules, rich in hydrogen and oxygen, and poor in carbon atoms, broke away. These parts escaped gradually as liquids or gasses, leaving behind wood with a larger and larger proportion of carbon atoms. Eventually the waterlogged wood was transformed into peat.

Over a period of millions of years, heat and pressure caused by the growing accumulation of mud and sediment over the swamp, worked to drive off much of the hydrogen and oxygen remaining in the peat. The carbonaceous substance that was left is called coal. The amount of carbon trapped in a particular type of coal depends on the age of the

deposit and the conditions under which the deposit was formed.

In order of development, the most immature form of coal is called lignite. Lignite is high in moisture and low in carbon. Next are bituminous (soft) and anthracite (hard) coals, containing less moisture and more carbon.

In this country the most familiar classification system for coals is the American Society For Testing and Materials' (ASTM) system. It categorizes coal by rank or according to the degree of metamorphism or progressive alteration in the natural series of coals, from lignite to anthracite. (Table XI) Volatile matter, fixed carbon, bed moisture and oxygen are all indicative of rank, but no one item completely defines it. In the ASTM classification, the basic criteria are the fixed carbon and the calorific values calculated on a mineral-matter-free basis.

Note that in establishing the rank of coals, it is necessary to use information showing an appreciable and systematic variation with (1) age, and (2) the physical conditions of coal formation. For higher rank coals, a good criterion is the "dry, mineral-matter-free fixed carbon or volatile." However this value alone is not suitable for designating the rank of the wet, lower rank

Table XI.

ASTM Specifications Classify Coals According to Rank

Class	Group	Fixed carbon limits, % (Dry, mineral-matter-free basis) Equal or Greater than	Equal or less than
1. Anthracitic	1 Meta-anthracite	98	--
	2 Anthracite	92	982
	3 Semianthracite[2]		
2. Bituminous	1 Low volatile bituminous coal	78	86
	2 Medium volatile bituminous coal	69	78
	3 High volatile A bituminous coal	--	69
	4 High volatile B bituminous coal	--	--
	5 High volatile C bituminous coal	--	--
3. Subbituminous	1 Subbituminous A coal	--	--
	2 Subbituminous B coal	--	--
	3 Subbituminous C coal	--	--
4. Lignitic	1 Lignite A	--	--
	2 Lignite B	--	--

[1]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface.
[2]If agglomerating, classify in the low-volatile group of the bituminous class.

Table XI.
(continued)

Volatile matter limits, % (Dry, mineral-matter-free basis) Greater than	Equal or less than	Calorific value limits, Btu/lb (Moist,[1] mineral-matter-free basis) Equal or greater than	Less than	Agglomerating character
2		--	--	
8		--	--	Nonagglomerating
14		--	--	
14	22	--	--	
22	31	--	--	Commonly
31	--	14,000[3]	--	agglomerating[4]
--	--	13,000[3]	14,000	
--	--	11,500	13,000	
		10,500	11,500	Agglomerating
--	--	10,500	11,500	
--	--	9,500	10,500	
--	--	8,300	9,500	
				Nonagglomerating
--	--	6,300	8,300	
--	--	--	6,300	

[3]Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[4]There may be nonagglomerating varieties in these groups, and there are exceptions in the high volatile C bit. group.

coals. For these, the "moist, mineral-matter-free heating value" is the chief criterion.

1. Analyzing coal. To select a coal for fuel requires that the power engineer understand the meaning of the various tests and methods of analysis that express coal qualities in figures instead of words. Principal characteristics are expressed in what is known as a proximate analysis. The proximate analysis is distinguished from an ultimate analysis, which shows the exact chemical composition of a fuel without reference to physical form in which the compounds appear. The ultimate analysis provides data needed for combustion calculations.

The proximate analysis of of more use to the engineer since it gives a good picture of a coal's behavior in a furnace. The procedure is relatively simple, and the results indicate the percentages of moisture, ash, volatile matter and carbon. Separately, the amount of sulfur contained in the coal, the ash-fusibility (fusion) temperature, and the fuel's heating value are determined.

Coal analysis can be made in several ways. The type use envisioned for the coal will determine which base is most applicable. For power plant work, as-received, air-dried or moisture-free analyses are generally used. Moisture

and ash-free, and moisture-and-mineral-free analyses are usually employed in classifying coals.

As the name implies, the as-received analysis reports the condition of coal as delivered to the laboratory. This comes closest to the conditions, as-shipped or as-fired; the values desired in practical work. Loss or gain of moisture between the times of sampling and analysis depends on the type of coal, its size, the weather conditions and the method of handling the sample.

2. Coal characteristics. The proximate analysis reports on the various characteristics that are of interest to the power engineer due to their overall effect on the power plant.

a. Moisture. All coal contains some natural moisture. For eastern coals the range of moisture content varies from 1% to 5%. Lignites may have moisture contents as high as 45%. This moisture lies in the pores and forms a true part of the coal, being retained when the coal is air-dried. Surface moisture depends on conditions in the mine and the weather during transit.

Information about moisture is important in that the handling characteristics and grindability of the coal are

affected by moisture. Overall plant efficiency is dependent upon coal moisture content due to the energy required to remove it. The removal of moisture can be external, as in coal driers, or it can be inside the boiler where combustion energy is lost in turning the entrained water to steam.

b. Ash. The incombustible mineral matter left behind when coal burns completely is ash. It may differ from ashes, as the power engineer knows them, because ashes taken from a furnace sometimes contain unburned carbon. Like moisture, ash is an impurity that increases shipping and handling costs. It must be removed from the furnace and the ship. Ash handling requires additional equipment and space over that required by ashless fuels such as navy distillate. The furnace must be designed to avoid problems with clinkering and slagging. Finially, an increase in ash content may impede burning such that carbon is carried over to the ash pit thus decreasing combustion efficiency.

c. Volatile matter. That portion of coal which is driven off in gaseous form when fuel is subjected to a standardized temperature test is volatile matter. It consists of combustible gases such as methane and other

hydrocarbons, hydrogen and carbon monoxide, and noncombustible gases. Since the quantity of volatile matter indicates the amount of gaseous fuel present, it affects firing mechanics. It also influences furnace volume and arrangement of heating surfaces.

d. Fixed carbon. The combustible residue left after the volatile matter distills off is fixed carbon. It consists mainly of carbon, but contains some hydrogen gases. The form and hardness of this residue are an indication of the caking properties of a fuel and are, therefore a guide in the selection of combustion equipment.

e. Sulfur. One major problem with coal as a fuel is the generally high concentration of sulfur contained within. Sulfur is present in raw coal in amounts ranging from trace quantities to as much as 8% or more. This sulfur is found in three forms. They are; (1) pyritic sulfur, which is sulfur combined with iron in the form of mineral pyrite or marcasite, (2) Organic sulfur or sulfur combined with the coal substance, and (3) Sulfate sulfur, in the form of calcium or iron sulfate.

Of these, the finely divided pyrites and organic sulfur are considered non-removable impurities on the basis

of economics. Sulfate sulfur, generally not over 0.1% by weight as mined coal, is not too important. Large chunks of pyritic material which can be as large as a foot in diameter, usually can be removed by cleaning the coal.

Sulfur is a problem in the use of coal due to its polluting properties and its corrosive attack on heaters, economizers and stacks. The pollution aspect is not now a problem at sea, but in some inport areas such as Long Beach Harbor, California, it is. The import problem can be solved by burning a clean fuel while in these areas. The corrosive problem is more diffucult to handle and requires a good initial design with emphasis on material selection and operating temperatures, in order to produce a plant with low maintenance cost. Pyritic sulfur also is a contributing factor to clinkering and slagging, and to spontaneous combustion of stored coal.

f. <u>Ash-fusibility temperature</u>. This is measured by heating cones of ash in a furnace generally arranged to produce a reducing atmosphere. The temperature at which the cone fuses down into a round lump is called the softening temperature. Other temperatures sometimes observed include that at which the cone tip starts to deform (the initial-deformation temperature), and that temperature when

melted cone spreads out into a flat layer (the fluid temperature). The softening temperature (or sometimes the spread between the initial-deformation and softening, or the softening and fluid temperatures) serves as the best single indicator of clinkering and slagging tendencies under given fuel-bed and furnace conditions. This characteristic is of importance in fuel selection. It insures compatibility between plant design and the fuel.

g. Heating value. There is more importance placed on heating value of coal than any other characteristic. In buying fuel you are buying energy units. For naval use, not only cost is important, energy density of the fuel is a significant factor. To use lignite in a ship designed for the energy density of bituminous coal would reduce the ship's endurance range by half. Where storage volume is limited the energy density becomes very important.

When a coal sample is burned in a bomb-type calorimeter filled with oxygen under pressure, the fuel's highest heating value (HHV) is measured. It assumes that the latent heat of water vapor contained in the combustion products is absorbed in the boiler. Since water vapor in the flue gas is not cooled below its dewpoint during normal boiler operation, this latent heat is not available for making steam.

Hence, for coals containing a lot of moisture, this latent heat for water is subtracted from the HHV to give the net value or lower heating value (LHV).

h. Caking, coking. Confusion often exists with respect to the proper use of these two terms. Wnen coal is heated in the absence of air or in an atmosphere very deficient in oxygen, volatile matter is driven off, leaving behind a residue of carbon. This is coke. It may take the form of small powdery particles, or it may fuse into lumps of various sizes and strengths. In commercial coke-making, the term coke refers to the lumps of marketable size and quality. Coking coals are used to produce them in a coke oven.

Coke formation, in one shape or another, represents an intermediate combustion stage in any fuel bed. In a boiler furnace, some coals become plastic and form lumps or masses of coke. (This type of coke usually is not of metallurgical quality, and often is referred to as semicoke.) The masses of coke are called caking coals. Those coals that show little or no fusing action are called freeburning.

Caking properties of a coal and the nature of the coke masses formed (size, strength, etc.) are valuable indicators

of a fuel's performance in the furnace. These properties can be determined to some extent with standard ASTM tests that measure the free-swelling index and the agglomerating index. The first test gives some indication of the tendency of an unknown coal to coke, and is useful in determining the extent to which natural oxidation may have destroyed the coking power of a known coal. The agglomerating index is used in the classification of coals to indicate the dividing line between noncaking coal and those having weak caking properties.

Although both caking and free-burning coals can be burned without diffuculty, and equally well in boilers fired with pulverized coal, this is not the case with all types of stoker firing. In general, caking coals are burned on underfeed stokers, which have moving rams or other means for breaking the masses of semicoke formed in the fuel bed. Free-burning coals are usually burned on traveling-grate or spreader stokers because there is no agitation of the fuel bed. Agitation should be avoided to prevent small pieces of coal from sifting through the grate and into the ash pit, where they might continue to burn. It must be realized that any unburned carbon lost to the ash pit will reduce combustion efficiency.

i. Grindability. This term is used to measure the ease of pulverizing a coal, in comparison with coals chosen as standards. In the Hardgrove test, the industry standard, a prepared sample of coal receives a prescribed amount of grinding energy in a laboratory pulverizer. Results are measured by weighing the amount passing through a 200-mesh sieve. Multiplying the weight passing the sieve, by 6.93 and adding 13 to the product, gives the Hardgrove grindability. Grindability values do not give a direct indication of pulverizer capacity or power requirements. These variables are affected by the size and type of pulverizer, feedsize, moisture content, and desired fineness.

3. Solid fuel versus liquid fuel. The number of individual solid coal characteristics with which the power engineer must be concerned in selecting a coal fuel serves to enforce the argument that coal presents more problems as a fuel than those encountered when a liquid fuel is used. Coupled with the added disadvantages of: (1) a low energy to weight ratio, (2) a low energy to volume ratio, (3) high ash content, (4) a greater slagging problem, (5) more difficult handling problems, and (6) a slower heat release rate requiring a larger furnace size with respect to liquid fuels, it is not surprising that coal has lost its popularity as

the availibility of petroleum has increased.

But the worsening oil supply problem coupled with the price advantage and abundance of coal, have earned coal another look as a naval fuel. The use of coal does not have to be limited to solid firing, since the production of syncrudes have come into the picture. They are of comparable worth to the presently used fuel oils. An additional option is the use of coal as an extender for fuel oil, by burning coal-oil slurries. The implications of each of these choices will be explored in the remainder of this thesis.

B. Coal as a solid fuel for Naval vessels

The use of coal as a fuel at sea is not new. The first combustors used on ships were the Scotch marine fire tube boilers (fig. 1). These were followed in development by the sectional header type water tube boiler (fig. 2). The development of coal firing at sea ended with boilers of the drum type (fig. 3). This design offered more flexibility in capacity, temperature and pressure. It was also more adaptable to meeting grate loading and furnace volume requirements for stoker firing. The advent of oil firing, shortly prior to World War I, brought to a rapid end the firing of coal on the high seas. Bunker C was available,

cheap, and offered advantages in handling and bunkering. Therefore, the design of the coal fired boiler ceased with respect to the at sea environment. Developments contunued for land based plants, and the changes and technology produced for those plants can now be utilized to develop a modern coal fired marine plant.

Coal fired ships will be larger than oil fired ships. This is due primarily to the greater volume required for fuel stowage. If low sulfur bituminous coal is assumed to be the fuel choice, it can be bunkered at a rate of approximately 618,000 BTU/ft.^{3}. Bunker C oil, on the other hand, can be bunkered at a rate of 1,062,000 BTU/ft.^{3}. Therefore it will require approximately 75% more fuel stowage volume if coal is the fuel choice over oil.

If more conventional coal firing methods are used, the fireroom size must also increase, impacting ship size. These more conventional methods are; pulverized coal firing, stoker feed, and traveling grate. These methods of burning coal require furnace volumes that are 2 to 2½ times larger than a conventional oil fired furnace. This, coupled with a more voluminous fuel feed and control system requires a larger fireroom.

More advanced firing systems, such as pressurized fluidized bed combustion, have the potential to reduce

the impact on fireroom size. The pressurized fluidized bed requires about 1/10 the plan area of a conventional coal fired furnace, but at present the ancillary equipment required to operate such a furnace negates this advantage.[12] Even if the fireroom impact is designed away, the added volume required by the fuel will yield the necessity for a larger ship.

For solid fuel firing to gain acceptance on modern naval vessels, it must be generations removed from the earlier plants. The modern coal fired plant must be capable of rapid response to load changes. It must be clean and easy to maintain, and less labor intensive than past coal fired plants.

1. The burning of coal. Both coal and oil are hydrocarbon fuels, but their combustion requirements differ. These differences are reflected in the size of the furnace required for each to burn efficiently. The conventional coal furnaces are of necessity, larger than their oil counterparts. This is best explained by describing the combustion process for each fuel. The two elements basic to both fuels are hydrogen and carbon. Sulfur and some other elements which might be present, burn and give off heat, but common practice considers the reactions as negligible. Hydrogen is

normally in gaseous form, and can be liquified only at extremely low temperatures, below minus 400° F. On the other hand, carbon is a solid that does not vaporize completely until its temperature reaches 6,300° F. Heating values are high: 62,000 BTU/lb. for hydrogen, and 14,100 BTU/lb. for carbon.

To burn coal or oil in a furnace, both fuels must undergo the same four steps. They include: (1) preparing the fuel and air, (2) converting the complex fuel into elementary fuels, (3) bringing these fuels and air together in the right proportions and at the proper temperature for ignition and combustion, (4) transferring heat from the products of combustion to the boiler or other surfaces, while retaining enough heat in the combustion zone to maintain volatulization and ignition. All of these actions occur at the same time in any furnace, and each particle of fuel traces the entire sequence, in order, in its brief passage through the furnace.

The physical characteristic difference between coal and fuel oil, which has major impact on furnace design, is coal being a solid and fuel oil being a liquid. In step (1) of the combustion process, preparing the fuel and air, coal (as a solid) cannot be divided as finely as oil. It consequently has much less fuel surface area in direct

contact with the oxygen in the combustion mixture. This results in coal having a slower burning rate, and therefore requiring a larger furnace volume for complete fuel combustion. Step (2), converting the complex fuel into elementary fuels, is related to step (1). The coal particles give up the contained volatiles to combustion with relative ease. But the combination of elemental hydrogen and carbon contained within the fuel particle is made more difficult by the outer layers of the particle, shielding the inner layers from needed oxygen. With fuel oil this is not so great a problem, since the fuel particles can be much smaller than when coal is used. Since the fuel is liquid, the furnace heat can serve to crack the parent molecules into elementary fuels. The slower burning of coal requires a longer residence time in the furnace, to insure complete combustion. In pulverized coal firing, this delay in heat release has the effect of changing the temperature profile through a furnace. With coal, the energy release is shifted toward the exit area, raising the temperature of the exhaust gases entering the boiler superheater region. To regain this energy, a desuperheater is added before the superheater, increasing the boiler size.

C. Modern methods for solid coal firing

Coal firing at sea is possible by a variety of means. The more common methods of burning coal in land based plants are fuel beds (spreader feed, chain and traveling grate and underfeed) and pulverized coal firing. Fuel beds provide the most economical method for burning coal in almost all industrual boilers rated less than 200,000 lb/hr of steam. In fuel bed firing, coal is pushed, dropped, or thrown onto a grate by a mechanical device called a stoker. Part of the fuel is distilled off as a combustible gas, which burns above the bed just like gaseous fuels. Coke remaining on the bed after distillation is burned in the presence of the air that flows up through the grate and the fuel. Ash left after combustion is usually removed from the furnace on a continous basis, by movement of the grate.

Stokers can be divided into two general classes, depending on the direction from which raw coal reaches the fuel bed. The overfeed type has coal coming from above, while the underfeed type receives its coal from beneath. The spreader and mass-burning stokers are overfeed types.

The fuel bed types of combustors have inherent disadvantages which would not be acceptable for use at sea for a modern naval combatant. With the exception of spreader stokers, the response to load change is poor. They all have a low range of tolerence for varing fuel quality.

The auxillary equipment requires more space to handle the fuel. Automation to handle the variety of load requirements experienced in an at sea environment, would be very difficult. Noise from the fuel handling equipment would increase self-noise, and degrade sonar performance. The plants are large and volume inefficient. Maintenance of the fuel feed equipment would be high. Dust would be a problem to contain, and present cleanliness standards aboard naval vessels are not often compromised.

There are other means of firing that show promise for use at sea. These are pulverized coal firing and fluidized bed combustion.

1. <u>Pulverized coal firing</u>. At present, the most common method of burning coal in central station plants is in the pulverized form. Pulverized coal firing will have inherent disadvantages over oil firing of a larger size requirement, both due to fuel volume increase and increased furnace size. But proper design for the use of pulverized coal would eliminate most of the disadvantages previously listed for fuel bed furnaces.

An impact study on firing pulverized coal was performed by Combustion Engineering, Inc.[17]. The impact of converting a V2M9-15 boiler, from oil to pulverized coal firing

was studied. The V2M9-15 boiler is designed for an mcr evaporation of 285,000 lbs./hr. at 955° F. and 870 psig. It is of a size to be used primarily on large tankers as a single main propulsion boiler. The results of the study were:

Burners - Increased the number of fuel compartments from four to twelve. This more than doubles the burner height, necessitating a three foot furnace height in this area. The burners may be either the tilting or fixed tangential design. Primary air (approximately 12% of the combustion air) will be blown into the fuel compartment with the pulverized coal. The remaining secondary air is blown into the air compartments.

Furnace - The lower furnace must be sloped approximately 60° from two opposing sides, thereby forming a V shaped hopper for collection of fly ash and slag. Since fly ash and slag require continous removal, the bottom of the furnace contains an opening which allows the remains to fall into an ash pit located directly under this lower furnace opening. Formation of this opening requires the installation of an additional lower waterwall header.

Superheater - Pulverized coal firing will increase the total steam temperature by 40 to 50° F., relative to oil firing. If steam temperature is to be maintained under oil fired, as well as coal fired conditions, the installed control

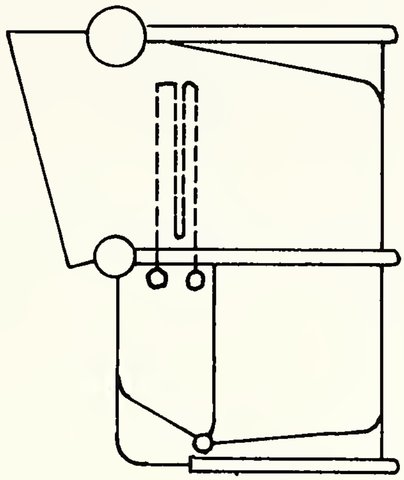
desuperheater capacity should be increased from 90° F. to 140° F.

(4) Fly ash shields- Since the fly ash produced by coal firing is a relatively abrasive substance, tube shields must be installed in certain areas of the boiler to protect against excessive tube errosion. The area necessitating the installation of these shields would be the leading edge of the screen, as well as those areas of the bank and superheater which receive direct steam impingement from the sootblowers.

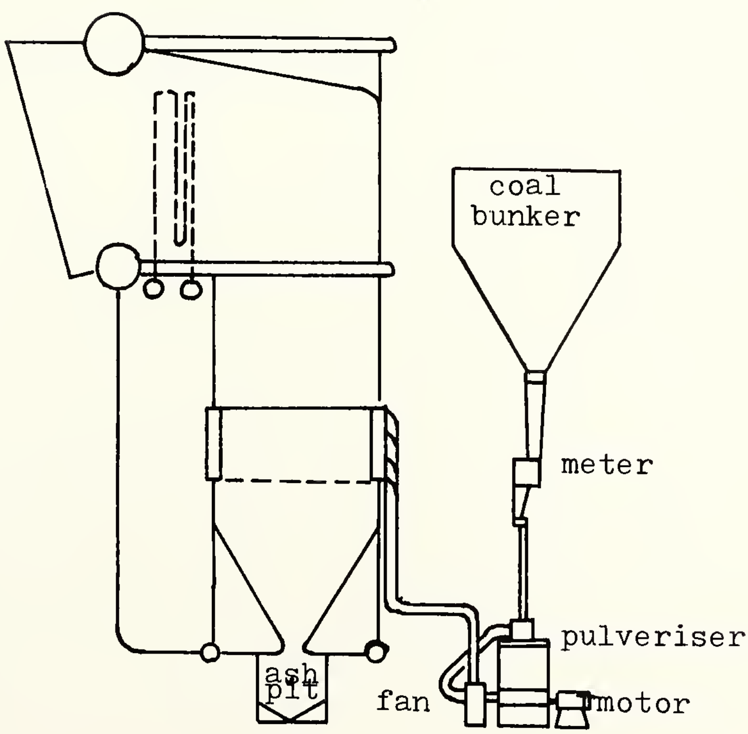
The relative impact on size, necessitated by these changes, is shown in figure 12. This is the impact on size of one boiler, the CEV2M9-15. In further discussion with Mr. Carl F. Horlitz, Assistant Manager-Engineering, for CE Marine Power Systems Division, it was indicated that a working rule of thumb for the volume increase in converting from oil firing to pulverized coal firing, is; the furnace volume is assumed to double. Weight increases, on the other hand, assume a 90% increase for the smaller size furnaces, with a 60% increase assumed for the larger sizes. This shows that there is some economy in scale available with respect to weight. These thumb rules will be of use later on in this thesis, in determining the overall ship size impact of converting from fuel oil to coal firing.

Figure 12. <u>OUTLINE OF AN OIL FIRED BOILER VERSUS A PULVERIZED COAL FIRING BOILER-V2M9-15</u>

<u>Oil Fired</u>



<u>Coal Fired</u>



A graphic representation of how a change from oil to pulverized coal firing would impact fireroom design, is illustrated in figures 13 and 14.[6]

Both plants are capable of an mcr evaporation of 250,000 lb./hr. at 900 lb./in.^{2} and 950° F. This would require a fuel feed rate of 28,450 lb./hr. for a coal having a LHV of 11,000 BTU/hr., as compared to a 16,000 lb./hr. feed rate for the oil fired boiler. For marine use for other than naval combatants, the coal would be prepared for use by pulverizing just prior to entry into the furnace. Not bunkering the coal in the pulverized state minimizes the risk of spontaneous combustion. The disadvantage of a pulverizer on a naval combatant is that it is noisy, reducing the ship sonar performance. Additionally, the increased signature being put into the water would enhance detection by other ships.

Carrying coal in the pulverized state would provide the advantage of fuel being easier to move from shore to ship, ship to ship, and bunker to furnace. Pulverized coal could be blown through pipes in much the same way fuel oil is pumped. This would yield a smaller fuel transfer system, and fuel transfer at sea would be similar to the transfer with fuel oils. Coal, if carried in the unpulverized form, would require a traveling belt type system

BOILER (OIL FIRED)
250,000 #/hr

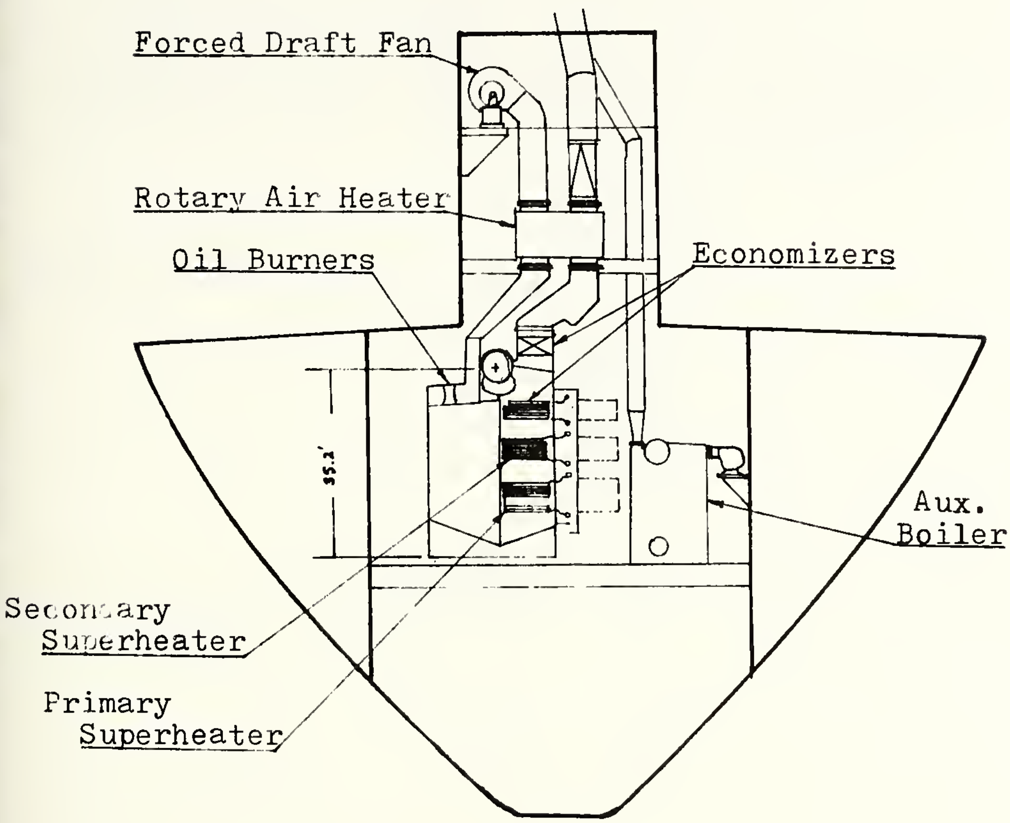


figure 13

BOILER (PULVERIZED COAL FIRED)

250,000 #/hr

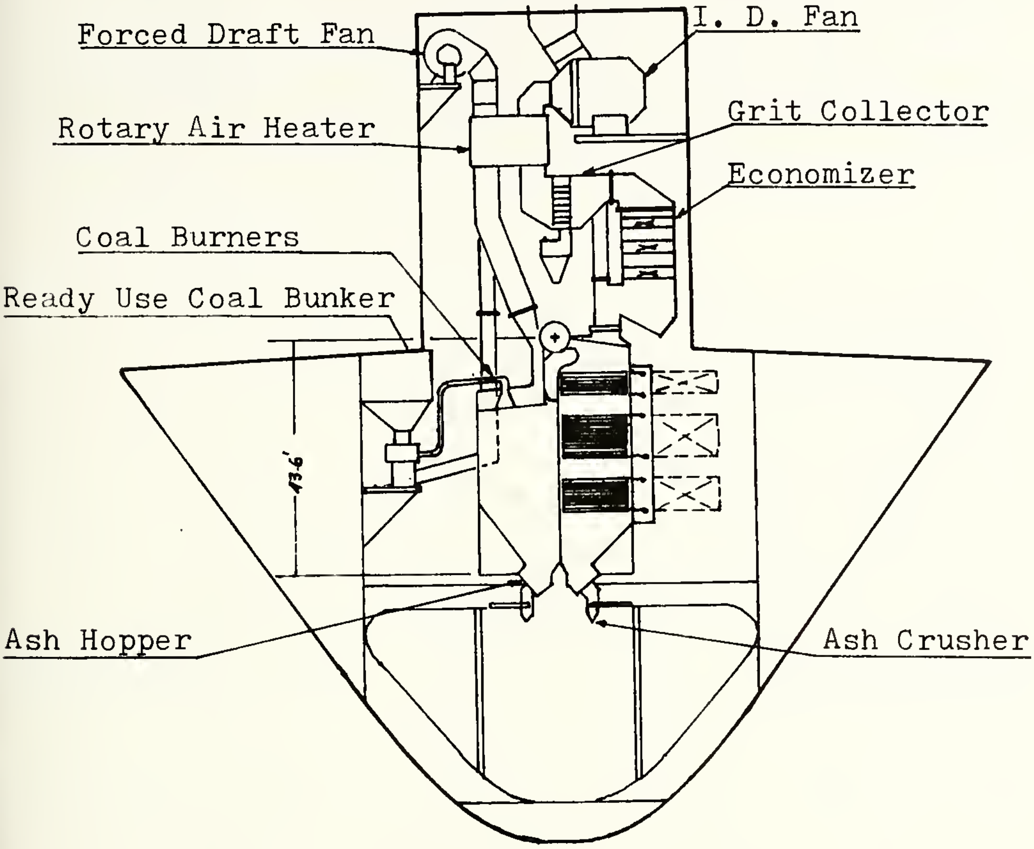


figure 14

to move the fuel around aboard ship. The bunkers would require an elevated location with respect to the furnace, if gravity is envisioned as the motive force. The latter is not practical due to the impact on topside design and ship stability. Transfer of fuel at sea would also be difficult and time consuming, since coal in the unpulverized state would require some high line technique such as that used for bulk stores.

A solution to the spontaneous combustion problem of pulverized coal is to blanket the fuel with a gas such as CO_2 or stack gas. The use of stack gas is the more attractive solution due to its availability and the elimination of the space and weight requirement for a CO_2 system.

A comparison of figures 13 and 14 provides some insight as to the impact of pulverized coal firing in the fireroom design. The coal plant is more dense than its oil fired counterpart. Topside space is impacted by the larger stack area required to accomodate the added furnace height, plus the addition of the draught plant, grit collector, etc., not required for the oil fired plant. In this example, with roof mounted burners, the mean furnace height is determined by burning length required for complete combustion of the fuel. For the boiler rating used in this example, the furnace height is fixed at 23 feet.

Combustion of the total fuel flow is shared by six burners, requiring a furnace plan section of 14 feet in width by 23 feet in depth. Products of combustion leave the furnace through a screen formed at the bottom of the membrane tube wall dividing the furnace from the convection pass, in which the gases flow upward over the primary superheater, secondary superheater and bare tube economizer. The width of this gas passage is fixed in relation to the depth of 23 feet, to give moderate gas velocity between the tubes. Furnace gas temperature and gas velocity are important parameters concerning risk of fuel slagging difficulties. But perhaps more difficult to contend with in a marine application is the risk of fuel type and quality varying in an unpredictable manner. This would give rise to plant operation difficulties. Coal would only become an acceptable fuel at sea if these problems were minimized. The next section on fluidized bed combustion presents a possible solution to the aforementioned problems.

2. <u>Fluidized bed combustion</u>. Currently the subject of much research, combustion of fuels in a fluidized bed has been held to offer many advantages. For this study the primary advantages are; (1) a great tolerance to fuel quality, not only in coal, but the ability to burn most

other hydrocarbon fuels with equal ease, and (2) modular construction with the attendant reduced fabrication cost, and a greater latitude in boiler arrangement.

The principle of fluidized bed combustion is illustrated in figure 15. The fluid bed, consisting of finely divided solids, is supported on a grate having openings through which combustion air may pass, but which prevent the back flow of the solids. As gas velocities are further increased, the bed becomes more turbulent and the carryover of entrained solids increases. When the fluid bed is used for combustion (fuel burning) purposes, it is usually composed of an inert material (sand or crushed coal clinker). If the consumed fuels create appreciable ash, some provision for removal is required. Normally ash is removed by "blowing down" and replacing a portion of the inner bed.

Submerging heat exchanger surfaces (boiler tubes) in the bed provides high heat transfer rates. Although the throughput area of the bed cross section must be kept low in order to avoid excessive carryover, vertical height requirements are correspondingly low; therefore fluid beds can be stacked to provide reasonably compact units. Unfortunately, in spite of its relative compactness, the dead weight for a fluidized bed unit with a capacity similar to

FLUIDIZED BED

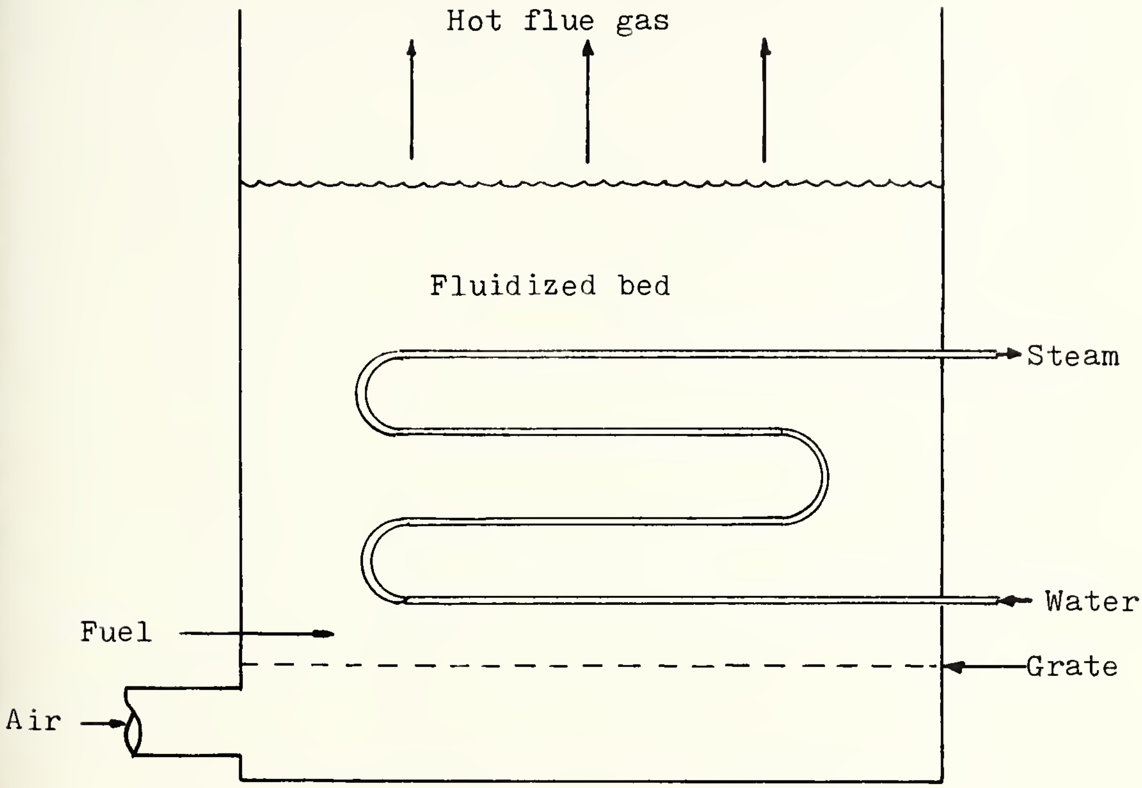


figure 15

that of a conventional marine unit would be much greater, due to the high inert bed weight.

Considering operation with coal as a fuel, startup must be accomplished by heating the bed with an oil or gas flame. The inert bed material fluidized by combustion air is heated by directing this flame downwards onto its surface. The flame temperature is above the melting point of the bed material, but melting does not occur because the bed particles are moving rapidly in and out of the flame zone, while the bed is in its agitated fluidized state. This causes the entire bed to become rapidly heated until, on reaching the coal ignition temperature, fuel is admitted. Ignition causes a further increase in bed temperature.

The coal can be in the form of roughly crushed particles. The size of the coal should be large enough to discourage spontaneous combustion, but small enough to allow air transfer for fuel movement. The turbulent nature of the bed particles will distribute the fuel evenly and fuel size will have little effect on performance. Other coal parameters such as type, ash, moisture, volatile content, coking or ash softening characteristics, have little effect. This offers a significant advantage to fluidized bed combustion, which could be of importance at sea.

The operating temperature level of the bed is dependent upon its construction. If, for example, the bed is enclosed by water cooled walls such as membrane tube panels, some of the heat released by combustion will be absorbed by these walls. The remaining heat is carried away by the products of combustion, which will be at a corresponding temperature. Therefore, the more of the total heat released which is absorbed by the walls, the cooler will be the products of combustion. Since these products have passed through the bed, the material in it will be at the same temperature; gradients within the bed being minimized by the rapid turbulent movements caused by the fluidizing process. Therefore, by selecting the correct ratio of cooling surface to heat release, the bed temperature and the leaving gas temperature can be arranged at a convenient level. This would be adjusted with regard to the duty of the bed and the characteristics of the fuel, particularly with respect to the ash fusion temperature. By operating the bed below the latter, ash corrosion and clinkering problems can be avoided. It may not be possible to obtain sufficient cooling from the use of the boundry walls alone, (depending on the bed size) in which case additional cooling surface will be immersed in the bed. This immersed surface may take the form of boiler tubes, superheater or reheater

tubes.

Compared to other methods of burning solid fuel, the fluidized bed offers a chance for increased efficiency due to the low amount of excess air which needs to be used. The fuel particles in the bed form only a small fraction of the total material therein. This amounts to from 2 to 7%, depending on the fuel characteristics. Each fuel particle is almost totally surrounded by hot inert material, providing a good ignition source. In this way the total fuel investment is distributed evenly across the combustion air flow. These factors assist in maintaining stable combustion conditions with as little as 5% excess air.

Figure 16 illustrates the arrangement of a fireroom, utilizing fluidized bed combustion. The boiler rating and terminal steam conditions are the same as those used for the previous oil fired and pulverized coal fired examples. In this example the fluidizing velocity of 4 ft./sec. was chosen, given a total bed area of 995 $ft.^2$ The unit is composed of 8 small beds, stacked four high on each side. The top two beds at each side are arranged with the primary superheater surface embedded within, whilst the bottom two beds on one side and the bottom bed on the other have generating surfaces embedded within. The

FLUIDIZED BED BOILER
250,000 #/hr

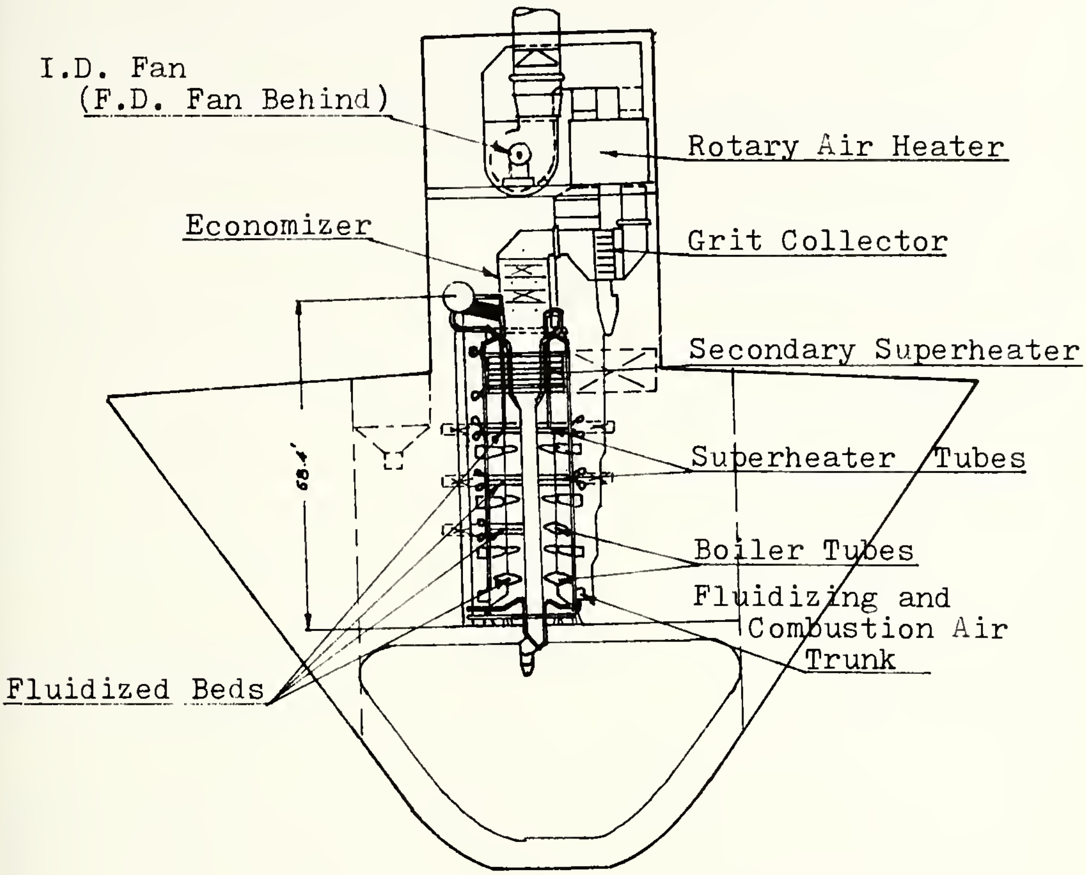


figure 16

remaining bed has some primary superheater and some generating surface. The boundary of the beds and the enclosure walls and gas passage are formed from membrane wall panels. Products of combustion leave the beds and pass, via the gas passage, to the secondary superheater arranged above the top beds, and then onward to the bare tube economizer and rotary airheater. Combustion air temperature for pulverized coal firing and stoker firing of coal is limited, but fluidized bed combustion is best accomplished with very hot air. In this case, the rotary airheater was used to give an air temperature to the beds of $625^{\circ}F$. Material collected by the grit collectors will be refired with the raw coal in the lower two beds.

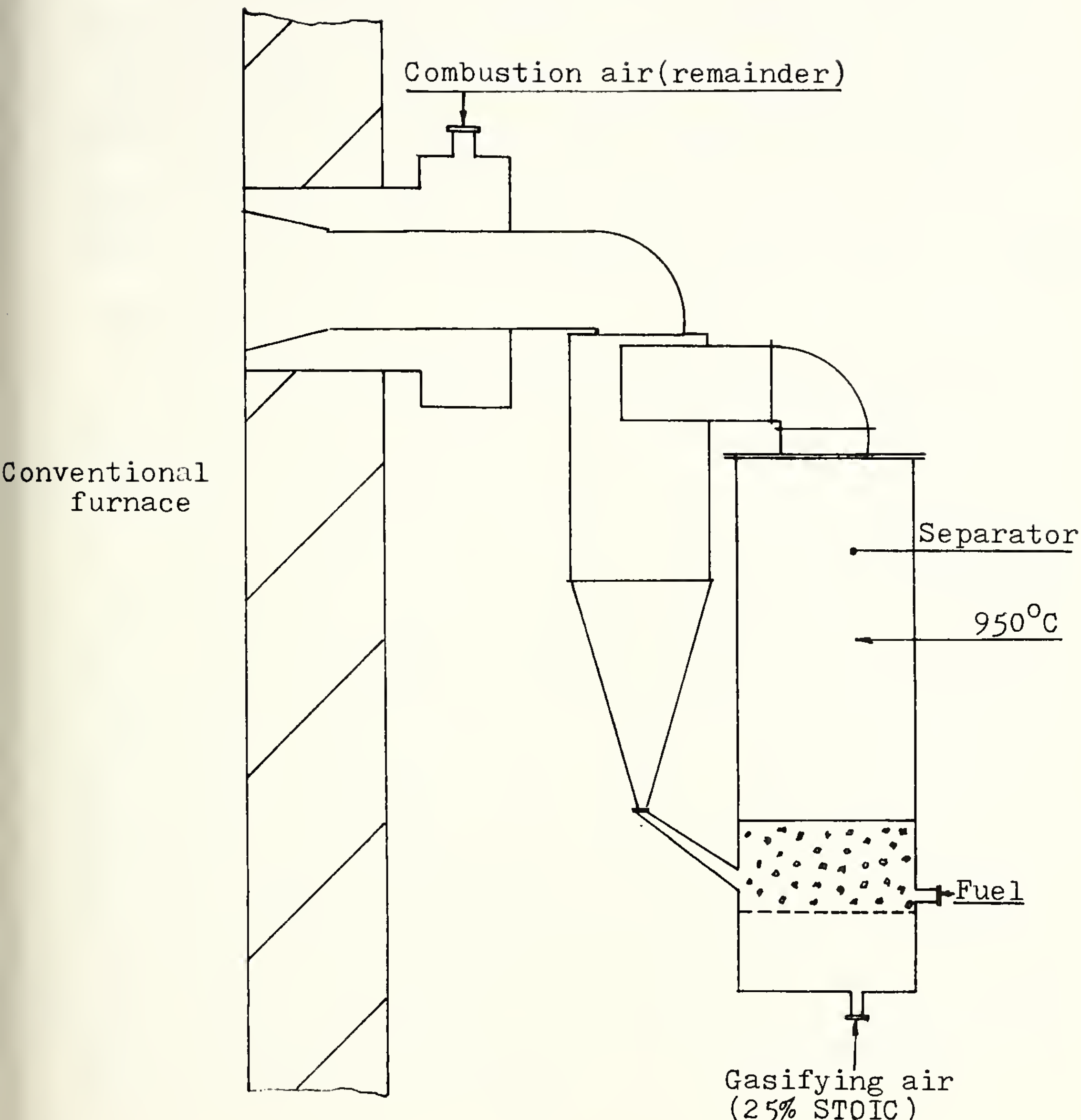
The above design configuration was selected for illustration because of its completeness. The approach taken in placement of the generating surfaces and superheating tubes is not a unique solution. It is just a representation of one solution out of many possible. The lattitude of changes possible, enable the fluidized bed combustor to be tailored to fit many different situations in order to best serve the terminal steam conditions, output required, and fireroom shape and space. This ability to be configured to fit the available space gives the fluidized bed plant an advantage over the pulverized coal plant.

3. <u>Other methods of solid fuel firing</u>. The fuel bed, pulverized coal firing and atmospheric fluidized bed are by no means the only methods of using coal in its solid form at sea. They do, however, represent the present state-of-the-art. The fuel bed has been used extensively in the past at sea, and its successes are well documented. The pulverized coal plant, in its modern form, has not seen any use at sea, but its use on shore is commonplace. The atmospheric fluidized bed combustor stretches the state-of-the-art by not now being widly used, but there are many pilot plants either under construction or in operation in a test mode. The inherent advantage of sulfur removal from the fuel by using a limestone or dolomite bed in a fluidized bed plant will insure its future development as this country shifts away from oil, towards coal.

An adjunct and logical progression to atmospheric fluidized bed combustion is pressurized fluidized bed combustion (PFB). Pressurized fluidized bed offers the advantage of a greatly reduced furnace plan area. For shore based power plant application it is estimated that the required plan area would be about 1/10 that required for a pulverized coal fired furnace, and $\frac{1}{4}$ that required for an atmospheric fluidized bed. "Present state-of-the-art designs negate the size advantage of PFB due to large size of the

ancillary equipment required for operation."[12] Additionally, startup and control of the furnace is a major problem using this combustion concept. This could easily be the most serious problem facing the PFB as a marine power plant, due to the varying load requirements it will operate under. These problems, coupled with the fact that PFB technology is still in its infancy, (only bench scale models exist) make it unlikely that this concept will find wide acceptance as a marine propulsion source in the near future.

Another concept that could have merit is the use of an in situ fluidized bed gasifier to produce a fuel gas from coal or a low grade liquid fuel. This concept differs from the previously mentioned processes, in that the processed fuel could be used in a conventional style burner. It could also find use as a fuel for a gas turbine plant, which seems to be the Navy's preferred method of powering conventionally fueled ships. The size of a gasifier is small, relative to an atmospheric fluidized bed furnace. In order to gasify the fuel, it is injected into a fluidized bed with about 25% of the air required for total combustion. The bed area required, therefore, is much less than that needed for fluidized bed combustion of the same quantity of fuel. (figure 17) This concept is more reasonable in the light of retrofitting presently built ships as a way



In Situ Fluidized Bed Gasifier

figure 17

to utilize low grade liquid fuels. The bunkering problem still exists if coal is to be used as the fuel. The design changes necessary to bunker coal aboard an existing ship would be too costly to render it an effective solution. For new designs it also makes little sense to gasify on a small scale, on each ship, what could be better done on a large scale at a central fuel process plant. A more complete explaination of fluidized bed gasification is presented in reference 18.

The list of possible alternative methods that might at some future date prove to be practicle as a marine propulsion method, could go on and on. Conversion systems such as open and closed cycle gas turbine systems (including combined gas turbine-steam turbine systems), supercritical CO_2 cycle, liquid metal Rankine topping cycles, magnetohydrodynamics (MHD), and fuel cells, all hold promise for the future. For the present though, we are limited to those systems which are already proven. For more advanced methods of coal firing, our selection is therefore limited to pulverized coal firing and atmospheric fluidized bed combustors. The next section will investigate the impact on ship design by these two methods.

VII. Design Impact. Coal Firing On Naval Vessels

A. Introduction

There is no question that a modern naval combatant can be designed to use coal as a fuel at sea. What is the cost of doing so? The cost will be evident in the increase in ship size. Therefore to determine the cost, an estimate of the impact on ship size must be made.

The approach used in this study was to select stated capabilities for an existing ship, and by using the Reed ship synthesis model,[19] calculate the size of ship required for different candidate power plants and fuels.

The capabilities selected were those from the latest U.S. Naval destroyer, the DD963. The design standards utilized were the same for each different propulsion configuration, and in concert with current Navy design practices. For the gas turbine powered example, this results in a smaller ship than the existing DD963, due to an increased margin included in the current design for future modifications. No attempt was made to include this increased margin in the candidate designs, since it would be subjective and would add nothing to the purpose of this study.

Reed's program presents a method for estimating the weight, volume, center of gravity, electrical load, and

other overall ship characteristics of conceptual designs. The program is applicable to surface displacement ships, and has been verified to produce accurate results for ships which range in size from 300 to 700 feet in length and 1,700 to 17,000 tons in displacement.

The program is tailored to meet four conditions. First, it strives to obtain a balance between weight and displacement. Second, the internal space available must be equal to or greater than the internal volume required. Third, the energy available must at least meet the energy required. Finally, the distribution of weight and volume must be such as to satisfy the design criteria for transverse stability, girder strength, and seakeeping. These conditions, for a feasible solution, require iterative processes within the model to obtain a satisfactory solution.

The space, weight and center of gravity are calculated using emperical relationships derived from measured values from already built ships of a similar type. Since no emperical relationships exist for coal powered ships, the relationships had to be estimated and the program modified, to accomodate. The ship powering variations selected for comparison were; the gas turbine, 1200 pound steam plant, 1200 pound pressure fired steam plant, atmospheric fluid-

ized bed, and pulverized coal fired plant. The last two have the added design impact of coal bunkering.

B. Modification of Reed's program

The following will explain the rational and assumptions made to develop pseudoempirical relationships applicable to coal burning ships. These relationships may then be directly substituted into the program deck, replacing the corresponding oil fired empirical relationships for those areas that will be affected by the change from oil firing to coal firing. As an example, a shift from oil to coal will impact the fireroom size. This is because coal combustors are larger than their oil counterparts. On the other hand, the engineroom size is assumed not to change, since both the oil and coal fired plants are capable of producing the same terminal steam conditions. It is possible that a better selection of steam plant parameters could reduce the overall ship design impact, when using coal as a fuel. This would be a second order effect, and would not add appreciably to the thrust of this study, which is size comparison. As such, it is a study of first order effects, keeping in mind that a more refined design could probably lessen the design impact.

To insure a consistency in the comparison between oil and coal firing, the ships developed must be capable of performing the same missions. Therefore, the maximum sustained speed, the endurance range, and the payload capability must all remain the same for each design. With these factors constant, any of the developed designs would be able to perform the military mission envisioned for the DD963.

Internal substitution of emperical relationships into the program deck was judged to be superior to externally constraining the program. The advantage is that the iterative solution technic built into the program was utilized.

The relationships requiring change in the program were those for fuel weight and volume, boiler weight, and machinery box volume. The changes to fuel weight and volume were considered to be the same for both the pulverized coal and atmospheric fluidized bed cases. This was not true for boiler weight and machinery box volume changes. For these, different relationships were developed and substituted for each case.

1. Modifications to the fuel relationships. The change to coal from oil requires modification to the relationships used for fuel volume and fuel weight.

a. Coal weight. The parent equation to be modified is the fuel oil weight equation. It is given in the program as;

$$W\ (816) = \frac{(ENDUR\ X\ FRSTM)}{(VEND\ X\ 2240)} \qquad (1.18)$$

where W (816) - fuel oil weight in tons

ENDUR - endurance range, nautical miles

FRSTM - all purpose fuel rate, lbs./hr.

VEND - endurance speed, knots

Low sulfur bituminous coal (12,000 BTU/lb.) will add approximately 50% increase in weight over fuel oil (18,500 BTU/lb.) based upon BTU content. This changes the fuel weight equation to;

$$\underline{W\ (816) = \frac{(ENDUR\ X\ FRSTM)}{(VEND\ X\ 2240)} \qquad (1.77)}$$

b. Coal volume. The parent equation for fuel oil is;

$$V\ (351) = 105.85\ X\ W\ (816)^{0.8532}$$

where V (351) - fuel volume, cu. ft.

Coal bunkers at 618,000 BTU/ft.^{3}, compared to oil at 1,062,000 BTU/ft.^{3}. Therefore an increase in bunkering

volume of approximately 75% is required. This changes the fuel volume equation to;

$$\underline{V\ (351) = 131.07 \times W\ (816)^{0.8532}}$$

2. <u>Modifications to the boiler weight relationships</u>. Since pulverized coal firing (PCF) and atmospheric fluidized bed (AFB) are not used as a propulsion means aboard ship, it is not possible to develop an empirical relationship for boiler weight such as those given in Reed's program for a 600 lb. steam plant, a 1,200 lb. steam plant, and a 1,200 lb. pressure fired (PF) steam plant. Since the program depends upon a relationship between boiler weight and shaft horse power, an alternate means of providing this information was used. Due to the lack of physical data, the relationships for boiler weight versus shaft horsepower were developed, using design estimates. These estimates were checked for validity where possible, with known results for land based installations.

a. <u>Boiler weight estimates for pulverized coal firing</u>. Estimates of boiler weight as a function of shaft horsepower were derived by using a rule of thumb provided by Combustion Engineering, Inc., Marine Power Systems Division.[17] A crude estimate of boiler weight is to double

the weight for a fuel oil fired boiler, designed to operate at the same terminal steam conditions. This method provides adequate correlation below 15,000 SHP, but becomes overly conservative at higher powers. The reason for this is that the increase in furnace volume required when using coal is necessary to accomodate the slower heat release rate. It therefore primarily affects the furnace section of the boiler. An examination of figure 12 serves to illustrate this point. The changes required to the boiler section of a converted marine boiler, are small compared to the changes required in the furnace section. It is estimated that for a 26,000 SHP power plant, the boiler weight would increase by a factor of 1.6, instead of 2. The boiler weight, W (200) relationship was derived by applying an economy of scale factor to the parent 1,200 lb. oil fired boiler.

$$W\ (200) = .00234\ \text{SHP} + 48.09$$

As modified for PFC:

$$\underline{W\ (200) = .0319\ \text{SHP} + 96.18}$$

b. <u>Boiler weight estimate for atmospheric fluidized bed</u>. To derive a pseudoempirical relationship for boiler weight as a function of shaft horsepower for an

AFB boiler, the system component weights were estimated using design data and relationships given in reference 11. Two similar plants were estimated. The first plant was the one illustrated in reference 6. This plant has an mcr evaporation of 250,000 lb./hr. at 900 lb./in.^{2} and 950° F. The second plant has the same terminal steam conditions, but the evaporation rate is one-half that of the first plant (125,000 lb./hr.). The results of these two calculations were plotted, and a straight line was constructed through both. This line is shown as curve 5 on figure 18. The resultant pseudoempirical relationship was checked for validity by comparison with weight data provided by reference 20. Reference 20 summarizes the results of a Babcock and Wilcox study on a 60,000 lb./hr. AFB stationary plant, with terminal steam conditions of 600 lb. per in.^{2} and 700° F. The weights of the pollution control equipment unique to a stationary plant were ignored. The estimated weight compared favorably with the results obtained using the derived pseudoempirical relationship. The proceedure and calculations used in developing the AFB boiler weight relationship, are illustrated below for the 250,000 lb./hr. plant.

Physical dimensions. (measured from figure 16)

Furnace section (outer box)

Plan size (W X W) = 14.76 ft. X 14.76 ft.

Furnace ht. (H_f) = 36.09 ft.

Superheater

Plan size (W X W) = 14.76 ft X 14.76 ft.

Height (H_g) = 11.48 ft.

Beds (eight)

Bed area (A_b) = 995 ft.

Expanded height (H_e) = 3.28 ft.

(1) <u>Weight of outer structure</u>. (W_{box}) This is the estimate of the outer plate weight assuming waterwall construction, with an effective plate thickness (T) of $\frac{1}{2}$ inch. (.04167 ft.) The density of the plate (D) is assumed to be 494.21 lb./ft.^{3}.

$$W_{box} = \frac{T\ (4HW + 2W^2)\ D}{2240} \quad \text{tons}$$

where $H = H_f + H_s$

$$W_{box} = 29.83 \text{ tons}$$

(2) <u>Weight of the expanded bed</u>. (W_{eb}) The calculation of the bed weight is simply the fluidized bed

volume, times the density of the inert-fuel mixture.

$$W_{eb} = A_b H_e D_e$$

where A_b = total bed area, ft.^{2}

H_e = expanded height (operating) ft.

D_e = expanded density of bed mixture - lb./ft.^{3}

W_{eb} = 129.67 tons

(3) Weight of bed heat exchangers. (W_{hx}) For a bed temperature of 1,550^o F., approximately 73% of the total heat transfer takes place in the bed. For AFB, heat transfer surface to bed volume ratio is limited to 10 ft.^{2}/ft.^{3}.

$$A_t = \frac{Q_b}{U_t \Delta T}$$

where A_t = area of tubes required, ft.^{2}

Q_b = total heat transfer in bed, BTU/hr.

U_t = heat transfer coefficient, 40 BTU/hr.-ft.^{2},F^o

ΔT = temperature differential, (1550-950) F^o

where $A_t = \dfrac{(250{,}000 \text{ lb./hr.})(1{,}482 \text{ BTU/lb.})(.73)}{(40 \text{ BTU/hr.-ft.}^2\text{-F}^o)(600 \text{ F}^o)}$

$$A_t = 1.127 \text{ X } 10^4 \text{ ft.}^2$$

check of surface packing ($\frac{A_t}{V_b}$) limit, where

V_b = volume of expanded bed

$$\frac{A_t}{V_b} = \frac{1.127 \text{ X } 10^4 \text{ft.}^2}{995 \text{ ft.}^2 \text{ X } 3.28 \text{ ft.}} = 3.45 \text{ ft.}^2/\text{ft.}^3$$

and is therefore less than the limit of 10 $\text{ft.}^2/\text{ft.}^3$

From reference 11, pages 77 to 82, the surface weight of the bed heat exchangers can be estimated.

$$g \text{ (surface weight)} = 20592 \text{ a } (1-a) \, d_o^2 \; \frac{\text{tons}}{10^6 \text{ft.}^2}$$

where $a = \frac{A_w}{d_o}$

$$A_w = \frac{A_w}{d_o}$$

A_w = average wall

d_o = outside tube diameter

From figure 6-37 of reference (11)

$a = 0.05$

From figure 6-40

$g = 10^3 \text{ tons}/10^6 \text{ ft.}^2$

therefore

$$W_{hx} = A_t \times g \times \frac{2000}{2240}$$

$$W_{hx} = (1.127 \times 10^4 \text{ ft.}^2)\left(\frac{10 \text{ tons}}{10^6 \text{ ft.}^2}\right)\left(\frac{2000}{2240}\right)$$

$$W_{hx} = 10.06 \text{ tons}$$

(4) <u>Weight of secondary superheater</u>. (W_{ss})

$$W_{ss} = \tfrac{1}{2} W_{hx}$$

$$W_{ss} = 5.03 \text{ tons}$$

(5) <u>Total of calculated weights</u>. (W_t)

$$W_T = W_{box} + W_{eb} + W_{hx} + W_{ss}$$

$$W_t = 174.6 \text{ tons}$$

(6) <u>Final adjusted weight</u>. To adjust for manifolding, headers, piping, internal supports, etc; W_T was increased by 20%.

final adjusted weight = 209 tons

A similar calculation for the smaller plant yielded a final adjusted weight of 183 tons. The resultant pseudoempirical equation for AFB boiler weight is;

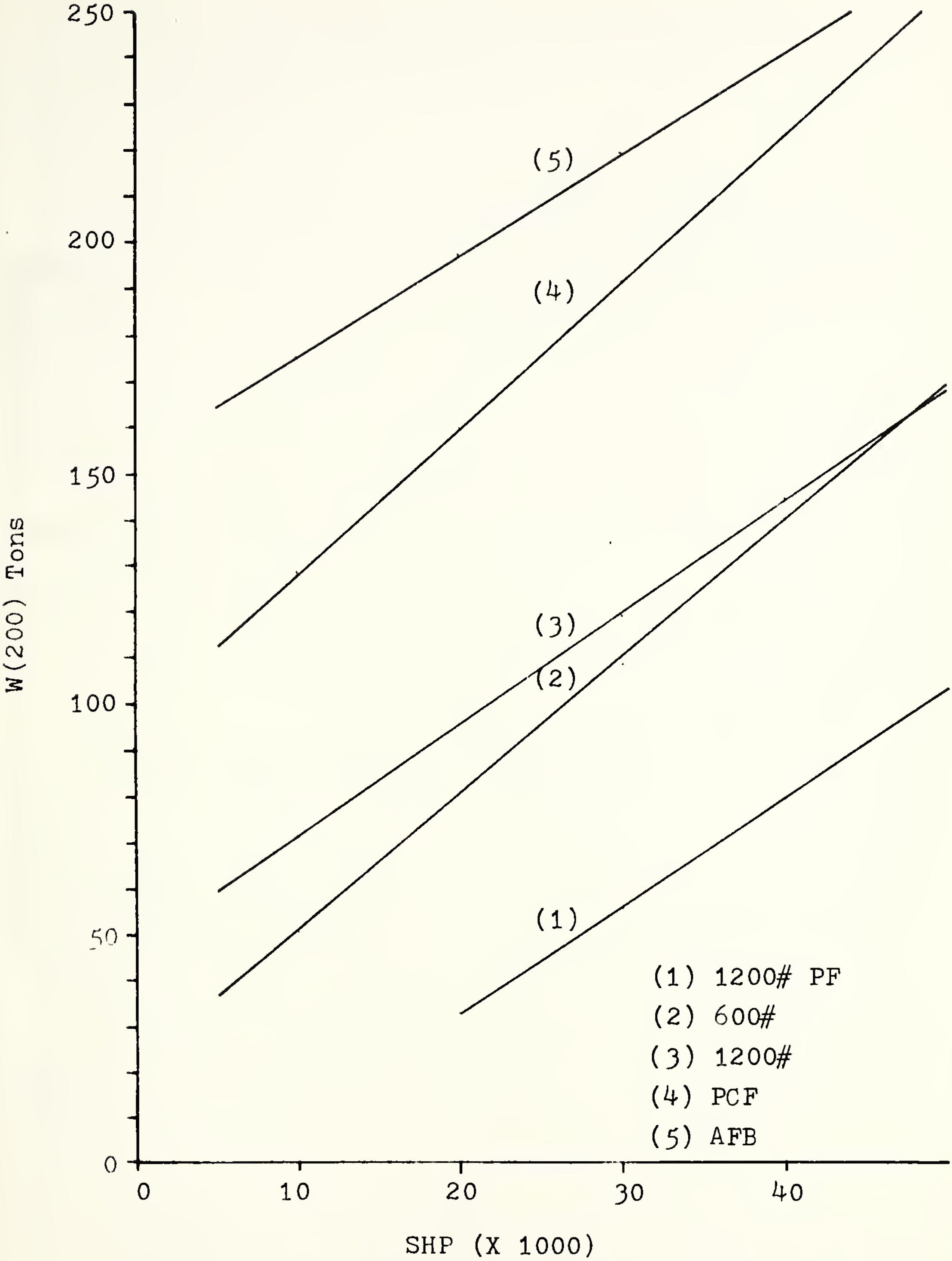
$$\underline{W\ (200) = .00218\ SHP + 153.75}$$

This equation estimates the weight of the AFB plant of reference 20, at 168 tons, as compared to the given weight of 170 tons. The developed equation therefore appears valid for first order approximations.

c. <u>Shaft horsepower versus boiler weight relationships</u>. The empirical relationships for boiler weight as a function of SHP used in the program are;

1200 lb. PF	W (200) = .00234 SHP - 14.08
600 lb. steam plant	W (200) = .00288 SHP - 21.92
1200 lb. steam plant	W (200) = .00234 SHP + 48.09
PCF	W (200) = .00319 SHP = 96.18
AFB	W (200) = .00218 SHP = 153.75

These equations are plotted for comparison in figure 18. It is interesting to note that the AFB is heavier than PCF, even though it requires only 40% of the PCF plan area. This



Shaft Horsepower vs Boiler Weight (W 200)

figure 18

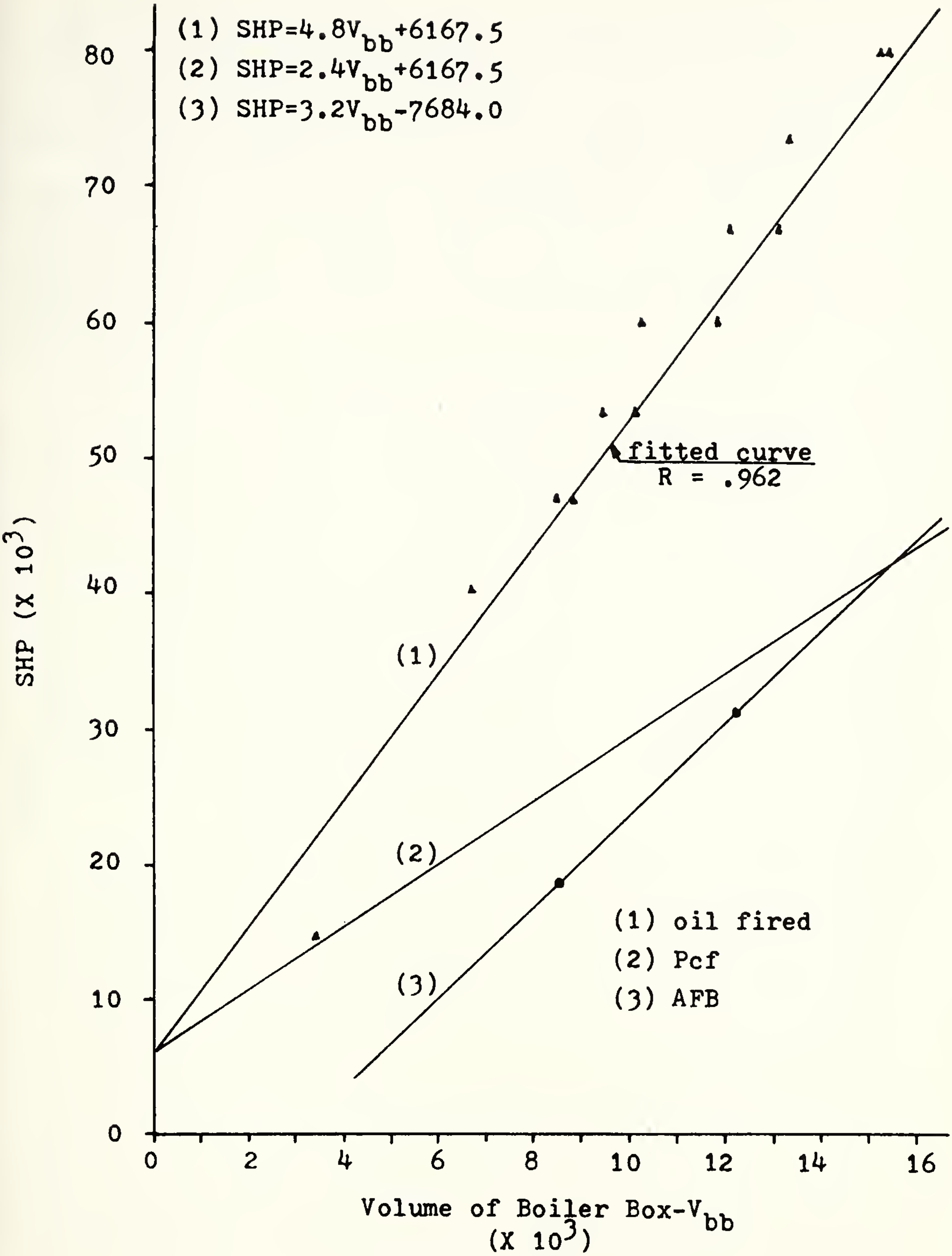
is due to the weight of the inert bed required for fluidized bed combustion.

3. <u>Modifications to the machinery box volume relationships</u>. The last of the empirical relationships requiring change to modify Reed's program for PCF and AFB, are the relationships for machinery box volume. The parent equation given in the program for machinery box volume is the same for all oil fired steam plants. It gives the relationship for machinery box volume as a function of SHP and installed electrical KW.

$$V\ (321) = 30{,}851 + 1.472\ SHP + 7.735\ (KWINST)$$

It was assumed that the volume change in substituting coal for oil, impacted only the fireroom size, and not the engineroom. This was reasonable in light of an earlier assumption that terminal steam conditions would be made the same for both oil fired and coal fired plants.

The general procedure followed was to select a 1,200 pound oil fired steam plant as the base plant. A determination of the relationship between SHP and boiler volume was made, using data for marine boilers provided by Combustion Engineering, Inc., and is illustrated in curve (1) on figure 19. The relationship between SHP and boiler



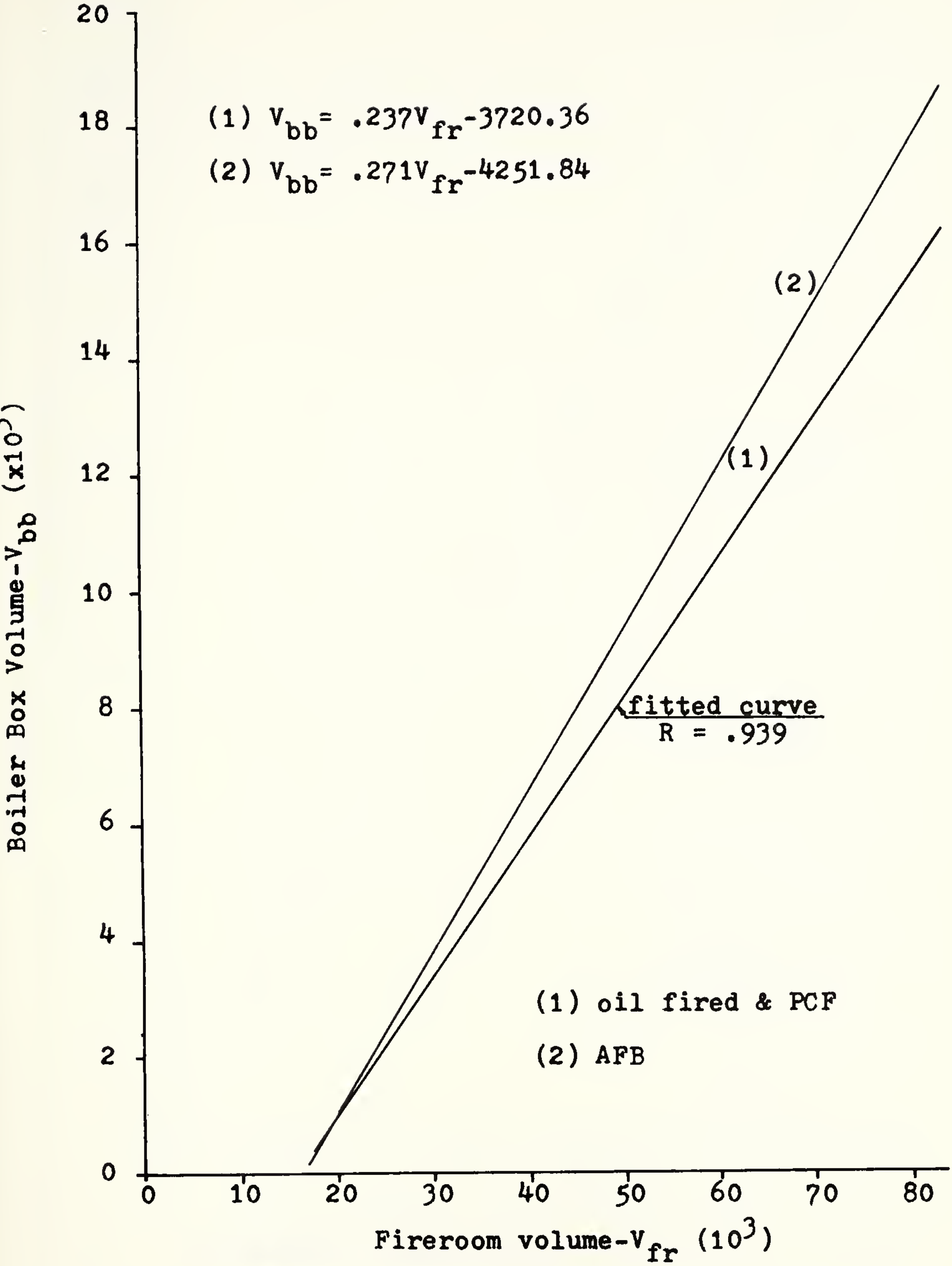
SHP versus V_{bb}

figure 19

volume for PCF and AFB, are also included on figure 19, as curves (2) and (3), respectively. Curve (2) for PCF was derived by doubling the boiler volume of curve (1). This factor was provided by reference 17. Curve (3) on figure 19 applies to AFB boilers, and was developed by plotting measured volumes for the two previously calculated AFB plants.

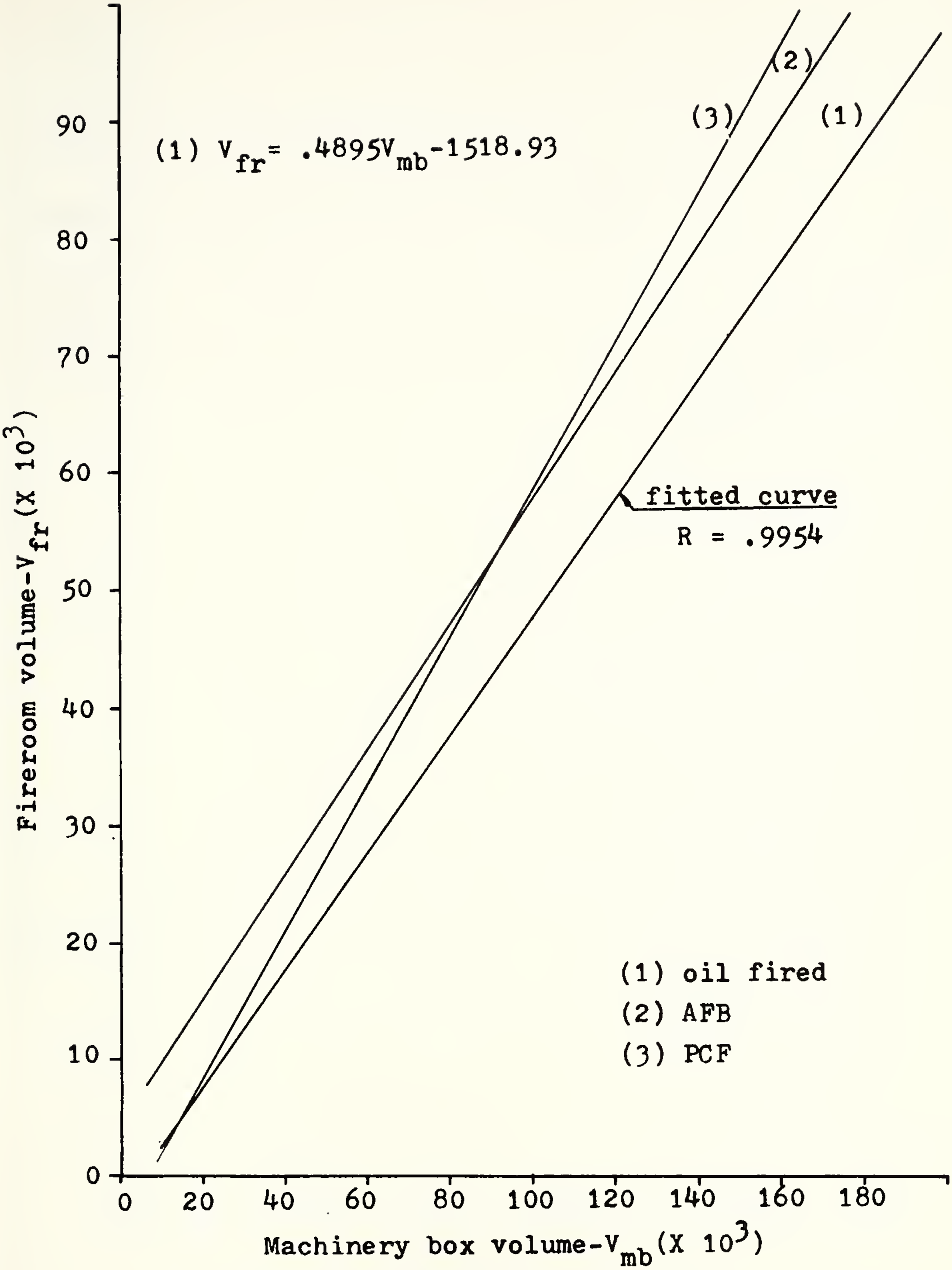
Data extracted from various Navy publications was then plotted to determine the dependence of fireroom volume on boiler box volume. This is shown in figure 20. The relationship between fireroom volume and boiler box volume was assumed to be the same for PCF as for oil fired steam plants. Due to the greater arrangement latitude afforded by AFB over PCF, an additional arrangement benefit factor of 7/8 was used to develop curve (2) on figure 20.

Curve (1) on figure 21 was developed by plotting data for machinery box volume as a function of fireroom data from various Navy sources. Curves (2) and (3) on figure 21, represent the increase in machinery box volume when the ship is designed for PCF or AFB. The increase in fireroom volume was obtained by fixing SHP, and extracting boiler volume from figure 19. This value was then used to enter figure 20, and determine the increase in fire-



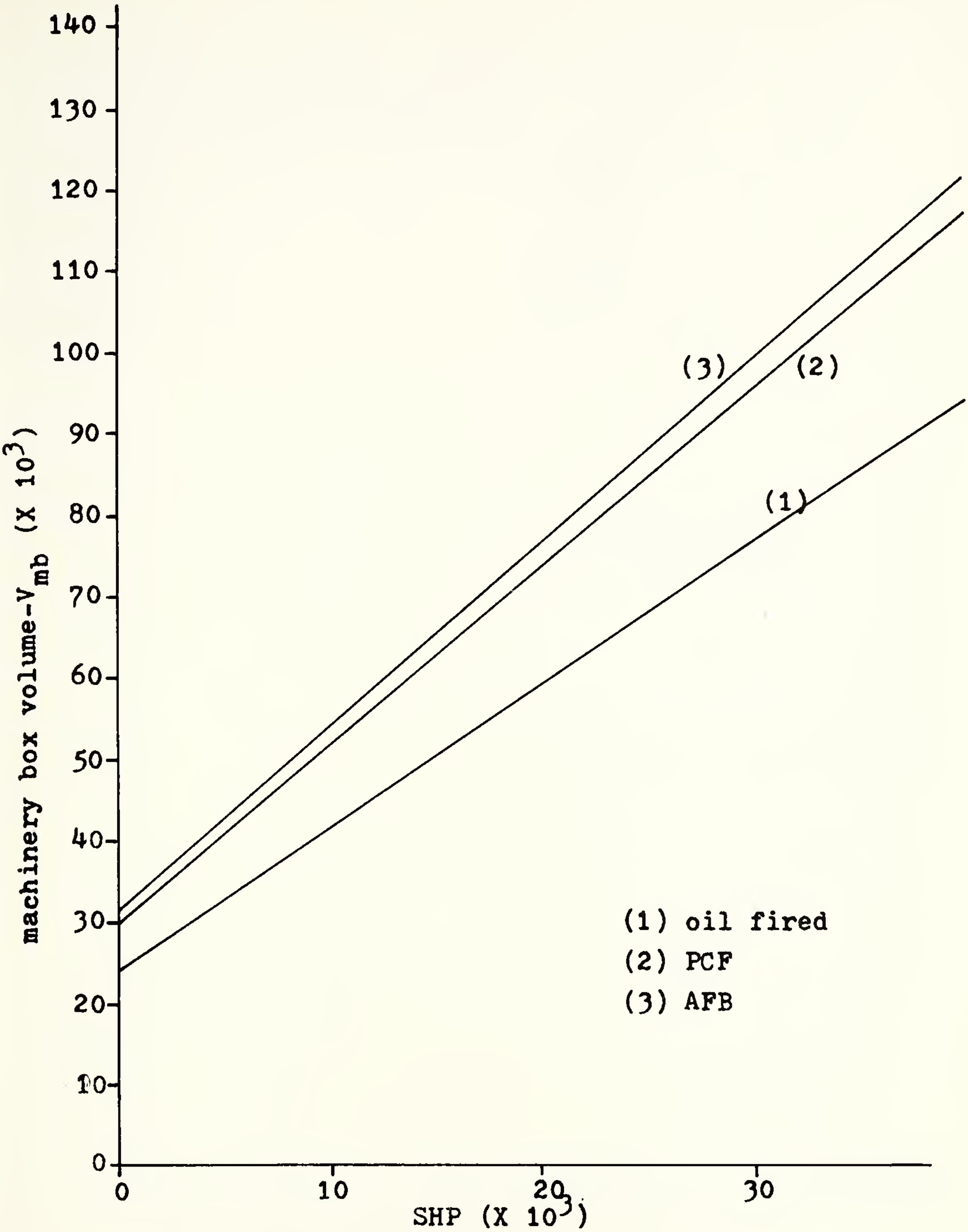
Fireroom Volume versus Boiler Box Volume

figure 20



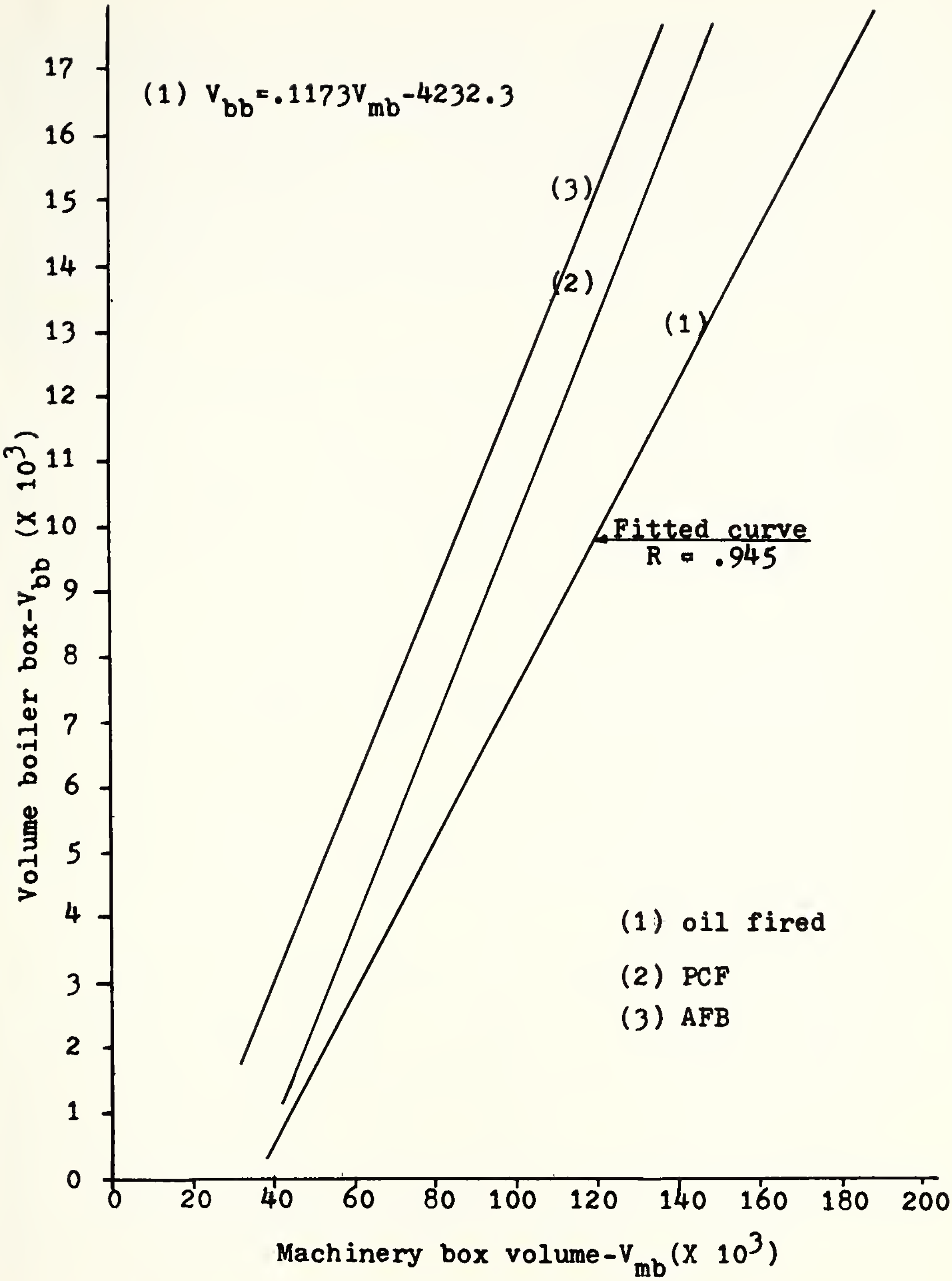
Machinery Box Volume Versus Fireroom Volume

figure 21



Machinery Box Volume versus SHP

figure 22



Machinery Box Volume versus Boiler Box Volume

figure 23

room size required for PCF and AFB. This increase in fireroom size is added to the machinery box volume. The values are plotted on figure 22, to produce curves (2) and (3).

The combination of the information from figures 19, 20, and 22 was then used to produce curves (2) and (3) on figure 21.

The final results are shown in figure 22. From the ratios of AFB to oil fired and PCF to oil fired, a scaling factor was obtained for modification of the parent machinery box volume equation. The resultant equations are;

for AFB (scaling factor=1.28)

$$V\ (321) = 39489 + 1.884\ (SHP) + 9.9010\ (KWINST)$$

for PCF (scaling factor=1.25)

$$V\ (321) = 38564 + 1.840\ (SHP) + 9.9669\ (KWINST)$$

4. Impact of designing for coal firing. The developed pseudoempirical relationships for coal firing were substituted into the program deck, replacing the corresponding empirical relationships for a 1,200 lb. oil fired steam plant. Reed's program was run for the following different powering variations:

(1) 1200 pound oil fired steam plant (1200#)

(2) 1200 pound pressure fired steam plant (1200#PF)

(3) gas turbine plant (GT)

(4) pulverized coal fired (PCF)

(5) atmospheric fluidized bed, 4 boiler (AFB#1)

(6) atmospheric fluidized bed, 2 boiler (AFB#2)

The maximum sustained speed, endurance speed, endurance range and payload capability were held constant for all cases.

Table XII summarizes the differences in each ship's principle characteristics.

Table XII.

PROPULSION TYPE	LBP ft.	BEAM ft.	DRAFT ft.	DISP FLD ton	SHP SUS	SHP END
1200#	472.57	46.71	17.88	5599.89	67537.6	9013.5
1200#PF	469.78	46.46	17.76	5501.48	66814.7	8927.6
GT	482.31	47.79	18.20	5953.41	70139.7	9340.4
PCF	523.89	48.99	20.95	7624.52	78123.1	10457.9
AFB#1	523.06	48.93	20.91	7586.20	77957.2	10429.7
AFB#2	523.68	48.97	20.94	7620.88	78081.8	10450.9

From table XII it can be concluded that to power this ship with coal would require an increase in displaced volume of greater than 25%. The increase in ship size is due to the required increases in both fuel bunkering and machinery plant size. This impact is summarized in tables XIII and XIV.

Table XIII.

PROPULSION TYPE	FUEL WT. tons	WT. FRACT.	FUEL VOL $ft.^3$	VOL FRACT
1200#	1127.7	.2014	42543	0.0693
1200#PF	1118.9	.2034	42260	0.0692
GT	1663.1	.2793	59262	0.0927
PCF	1913.1	.2509	82696	0.1048
AFB#1	1908.8	.2516	82536	0.1042
AFB#2	1912.0	.2509	82656	0.1042

Table XIV.

PROPULSION TYPE	BOIL&COND WT tons	MACH BOX WT tons	MACH BOX VOL ft^3	MACH SYS WT tons	MACH SYS ft^3
1200#	206.1	862.5	168941	1139.6	199220
1200 #PF	142.3	804.3	167877	1071.0	197727
GT	-	561.5	164993	959.9	224320
PCF	345.4	1158.0	257062	1494.5	295482
AFB#1	323.7	1136.3	260618	1472.1	298896
AFB#2	324.0	1137.5	260853	1473.9	299238

5. <u>The cost of designing for coal</u>. The cost difference in using coal vice fuel oil is probably the most difficult conclusion to draw. Most estimating technics are subjective and tend to enforce the estimators predetermined conclusions. As an example, coal has a definate advantage over oil in cost, on an equivalent BTU basis. On the other hand, coal burning has a deleterious impact on ship size. This, coupled with the increase in power plant cost, reduces the fuel cost advantage. The final cost of coal burning will depend upon how the estimates are made.

Even if the above estimates are accurately made, there are second-order effects that could overshadow any advantage that coal might have. Any comparison tends to be between ships, on a one to one basis. This ignores the refueling and tender support problems presented by coal. Coal would require a completely different fuel transfer system from that now used for oil. New tenders and resupply ships would have to be built. It would be difficult to continue the practice of refueling screen destroyers from carriers if there was a fuel requirement mix, with some ships requiring oil and others coal.

The use of coal by naval ships would have to be on a

fleet-wide basis. This would necessitate gearing the building program for replacement ships, for coal burning. This is not to say that a transition to coal is impossible. It would be less difficult in some respects than the transition from coal to oil which the Navy experienced in the early 1900's. Modern coal plants such as AFB and PCF can easily be built with a dual fuel capability that would lessen the transition impact. The cost would be larger, and more expensive ships would be needed for performance of the same mission. Any savings in costs would only be realized in those cases where coal could be used. The benefit of this approach would be a lessening of the impact on national security, in the event of another oil embargo. Another advantage is that the Navy would be better prepared to switch to coal if it became a necessity due to dwindling supplies of petroleum. Finally, in the case of AFB, this type plant is able to utilize any hydrocarbon fuel that might develop in the future, to replace oil. Therefore the conversion now insures greater future flexibility in regard to fuel selection.

To obtain some insight as to the cost savings that might be possible if coal is used as a fuel, a comparison of the previously developed destroyer types was made. The results are based upon a one to one comparison of

different ship types, with no attempt to include a cost for the second-order effects. The major areas that were costed for comparison were; (1) fuel cost difference between coal and oil, (2) initial cost of the various power plants, (3) differences in structural weight and attendant cost, and (4) cost differences in maintenance between plants.

a. Structural weight cost. The six previous design variations on the DD963 were compared for differences in structural weight. These differences were then costed at $2700/ton. This figure was derived from discussion with several Naval shipyard representatives, and includes yard overhead. The results of this comparison are shown in table XV. The differences in structural weight are given for each comparison, with the cost difference in millions included in parentheses above the weight differential.

b. Machinery plant cost. Cost functions for the 1200 lb. steam plant and the gas turbine plant were derived from functions given in reference 21. The relations were modified to represent 1977 dollars, assuming a 5% infla-

tion factor.

Table XV.

Structural Weight Cost Differences					
Base Plant / Changed To	AFB#1	PCF	GT	1200#PF	1200#
AFB#2	(.08) 28.15	(.04) 16.14	(1.2) 429.44	(1.7) 643.69	(1.7) 628.24
AFB#1	-	(.03) 12.01	(1.1) 401.29	(1.7) 615.54	(1.6) 600.09
PCF		-	(1.1) 413.30	(1.7) 627.55	(1.7) 612.10
GT			-	(.60) 214.25	(.50) 198.80
1200#PF				-	(.04) 15.45

Figures represent the differences in structural weight, with the cost difference in millions (in parentheses) above the weight increase.

(1) 1200 lb. steam plant

$$IC_{sp} = 6.99 \left(\frac{SHP}{1000}\right)^{.6} X\ 10^5\ (\$)$$

(2) Gas turbine plant

$$IC_{GT} = 7.64 \left(\frac{SHP}{1000}\right)^{.629} X\ 10^5\ (\$)$$

The cost of the pulverized coal fired plant was derived from equation (1) above. The changes to the machinery plant were assumed to be limited to the boiler, boiler controls and fuel feed system. The increases in cost in these areas, over an oil fired plant, are expected to be on the order of a factor of 2 to $2\frac{1}{2}$.[6] Cost data from various naval publications indicates the cost of this equipment represents about 25% of the total plant cost. Therefore, if the $2\frac{1}{2}$ factor is assumed for PCF, the total plant cost will increase by 37.5%.

(3) PCF plant

$$IC_{PCF} = 9.61 \left(\frac{SHP}{1000}\right)^{.6} X\ 10^5\ (\$)$$

For the atmospheric fluidized bed case, the cost in-

crease in the impacted areas was assumed to be less than that for PCF. This was due to the cheaper fabrication cost for AFB combustors over PCF furnaces. Therefore, a factor of 2 was used to represent the increase in the impacted areas. Again, equation (1) is modified, this time by an increase of 25% over the oil fired case.

(4) AFB plant

$$IC_{AFB} = 8.74 \left(\frac{SHP}{1000}\right)^{.6} X\ 10^5\ (\$)$$

The initial plant costs based upon SHP from table XII were calculated and are represented in table XVI. The numbers in table XVI represent the cost of the coal fired plant over the oil fired plant.

Table XVI.

	1200 lb.	GT
PCF	$4.38 M	- $1.34 M
AFB	$3.18 M	- $2.54 M

c. Fuel costs. At its present price, fuel oil may represent as much as 20% of the total life cycle cost (LCC) for this type vessel.[5] The price trend for coal, as represented in figure 11, is running at about half that of oil, on an equivalent BTU basis. If this trend is assumed to continue, the savings in fuel cost could be as much as 10% of the life cycle cost. For a ship of this size, LCC could exceed 500 million dollars. Therefore, the savings in fuel costs were assumed to be 50 million dollars, over 25 years.

d. Maintenance cost. Some increase in maintenance cost was assumed for coal firing. There was an increase in personnel of 12 men, for the coal fired ships. Their costs were assumed to represent the increased maintenance cost of coal over oil.

$$\text{Maintenance cost} = 12 \text{ men} \times 20{,}000 \text{ \$/yr.} \times 25 \text{ years}$$
$$= \$6 \text{ M}$$

e. Structural weight difference summary. AFB and PCF are compared against 1200 lb. and GT plants, to determine the cost impact of coal burning. The cost saving is based upon a LCC basis.

$$CS = F + MP + M$$

where CS = cost savings using coal, life cycle

F = fuel cost savings of coal over oil, 50 M

S = structural cost differential, table XV

MP = machinery plant differential, table XVI

M = coal maintenance cost, life cycle, 6 M

Case 1: AFB versus 1200 lb.

$$CS_1 = 50 - 1.7 - 3.2 - 6 \text{ M}$$

$$CS_1 = \$39.1 \text{ M over 25 yr. life cycle}$$

Case 2: AFB versus GT

$$CS_2 = 50 + 2.5 - 1.1 - 6$$

$$CS_2 = \$45.4 \text{ M}$$

Case 3: PCF versus 1200 lb.

$$CS_3 = 50 - 1.7 - 4.4 - 6$$

$$CS_3 = \$37.9 \text{ M}$$

Case 4: PCF versus GT

$$CS_4 = 50 - 1.1 + 1.3 - 6$$

$$CS_4 = \$44.2 \text{ M}$$

Table XVII.

Cost Savings Using Coal (LCC)		
Base plant / Changed To	$1200^{\#}$	GT
AFB	\$39.1 M	\$45.4 M
PCF	\$37.9 M	\$44.2 M

These numbers are impressive, compared to the ship's initial cost of \$100 M. But it must be remembered that they disregard the secondary effects such as fleet support problems and fuel inconvience factors associated with coal burning. If these factors are included, there is probably little advantage, cost wise, in coal as a fuel for a naval vessel. For these savings to be fully realized, it would require a fleet of ships dedicated to coal burning, with associated support equipment.

f. Volume penalty cost summary. Another method of determining the cost of coal burning is one based on

a volume penalty. In this regard, a lost cubic foot of hull volume for a destroyer costs about 30 to 40 dollars.[22] The rational is that if the volume is saved in one area, it may be utilized to meet the needs of another. The dollar figure includes the total impact of added volume on ship cost. The volume penalty figure must be adjusted for changes such as the initial cost of different types of propulsion plants. A change in fuel type and the associated cost change also must be adjusted. The volume penalty would include an increased manning factor for increasing ship size, so it isn't necessary to include this factor again, as in the preceding example.

The procedure used in calculation cost savings based upon a volume penalty was: first, determine the hull volume differences and associated costs (table XVIII); second, determine initial plant cost differences (table XVI); and third, add the $50 million fuel cost savings of coal over oil. The results are summarized in table XIX.

Table XVIII.

Volume Cost Impact						
Base Plant / Change To	AFB#2	AFB#1	PCF	GT	1200#PF	1200#
AFB#2	-	(.09) 2313.8	(-.03) -764.6	(5.7) 141948.7	(7.2) 180535.2	(6.9) 17213.2
AFB#1		-	(.12) -3078.4	(5.6) 13934.9	(7.1) 178221.4	(6.8) 169809.4
PCF			-	(5.7) 142713.3	(7.3) 181299.8	(6.9) 172887.8
GT				-	(1.5) 38586.5	(1.2) 30174.5
1200#PF					-	(.34) 8412.0

Figures represent the differences in hull volume, with the cost difference in millions (in parentheses) above the weight increase.

Table XIX.

Base Plant / Changed To	Cost Savings Based on Volume Penalty	
	1200	GT
AFB	$40.0 M	$46.9 M
PCF	$38.8 M	$45.6 M

The results (of this method of calculating cost savings) does not differ significantly from those based upon the changes required in structural weight (table XVII).

VIII. Coal Use On Existing Ships

A. Introduction

From the preceding section, it has been shown that various forms of coal firing for new construction applications are feasible. However, feasibility alone in only a first step in determining the merits of a design. Coal firing presents significant problems in space, weight, potential cleanliness, maintenance, and the design of fuel and ash handling systems. As diffucult as these problems are for a new design, they can be solved. But for the existing ship they present such serious complications that retrofit from oil to coal is an unlikely solution. This is particularly true of warships, since they are now designed with either weight or volume limitations.

Therefore, for the existing ship, the use of coal will be limited to liquid-solid fuel blends and syncrudes derived from coal.

B. Liquid/Solid fuel blends

The use of a fuel oil - coal mix provides an economical means of burning coal in an existing ship. The use

of coal/oil slurries have been investigated during both world wars as a means of alleviating temporary shortages of oil. In both instances, the crisis ended before conclusive results could be obtained. However, there is sufficient data to indicate a reasonable chance of success.

ERDA has an ongoing program to research coal/oil mixture combustion.[1] The thrust of the program is to determine the extent to which refit technology can be practically implemented. Four contractors are presently in the program, and modification of their equipment to use and evaluate slurries has already begun. The contractors and their projects are:

City Public Service San Antonio, Texas	Coal-oil mixture combustion, Utility Steam Generator, 60 mw, Originally Designed for Gas- Late FY 1979 Completion
New England Power Co. Salem, Mass.	Coal-oil Mixture Combustion, Utility Steam Generator, 80mw, Orig. Designed for Coal, Conv. to Oil - Early FY 1980 Completion

Accurex Aerotherm Mountainview, California	Coal-oil Mixture Combustion, Process Industrial Steam Generator, 80,000 lb./hr. Steam Originally Designed for Oil/Gas Early FY 1979 Completion
Interlake, Inc. Chicago, Illinois	Coal-oil Mixture Combustion, Blast Furnace - Early FY 1979 Completion

ERDA was also scheduled to begin an analysis of marine applications for coal/oil slurries late in 1977. Also in 1977, the Swedish company, Stal-Laval, in concert with a major oil company, applied for a patent on a coal/oil slurry process they had developed.

A recent pilot plant test conducted on a 1974 project by a major U.S. auto manufacturer, proved very successful. This test was run using a 10,000 gallon slurry composed of 70% No. 2 fuel oil, and 30% pulverized coal. This mixture was burned in their industrial boiler. Visual examination revealed no damage to the fuel pump burner assembly or burner. The small amount of powdered ash that accumulated on the floor was easily removed. The only problem encountered

was the instability of the fuel suspension during transportation and storage. For the tests, this problem was solved by agitation. However, additives are available and are being investigated to reduce this problem. Suspension is a function of the viscosity of the oil, and can be expected to be much better when heavy oils are used.

With the use of medium and high ash coals, stock emission of particulate matter is a problem. Marine applications on existing ships would probably be limited to coals with less than 6% ash. Even with low ash coals, some type of dust collector is likely to be needed.

The cost of coal is presently about one-half the cost of oil on an equivalent heating value basis. Tests have shown that the maximum blend of coal and oil is limited to about 40% coal by weight. Beyond this, the slurry is difficult to pump. Assuming that a 40% coal mixture can be burned, and allowing a reasonable cost for pulverizing and mixing the slurry, a fuel cost savings of 15% to 18% appears possible. This would result in a LCC saving for a ship the size of the previously developed destroyers, of 15 to 18 million dollars. In addition to the cost savings, the use of fuel oil has been lessened by 40%. This could be of greater importance than the cost

saving, considering the impending world shortages in petroleum. It is interesting to note that the blend has slightly more BTUs available per cubic foot. Hence no increase in bunkering would be required.

Slurries would not be satisfactory for present gas turbine powered ships, due to the corrosive problems encountered between coal by-products and turbine blades. If slurries found wide acceptance with the U.S. Navy, this problem would have to be solved or the gas turbine plant would lose its current popularity.

Coal/oil mixtures as a fuel replacement are not a solution to the oil shortage problem. They are oil extenders, and as such, serve only to delay the inevitable. A more logical use of slurries would be to use the cost advantage of solid coal to offset the expense of coal derived syncrudes to produce a fuel that is competitive with oil, pricewise. This would allow the use of a totally coal derived liquid fuel, at a cost comparable to oil. The price would be more stable than its petroleum-based counterpart, since it is a blend of domestic products.

C. <u>Liquefaction of coal</u>

The production of a liquid fuel from coal, to be used

as a marine fuel, is already a reality. During the latter part of 1973, the U.S. Navy ran tests with Coal-Oil-Energy-Development (COED) derived fuel oil. The fuel used was a blend of two synthetic crudes derived from Illinois No. 6 coal, and Utah King Coal. The blend had a flash point of only $58^{o}F$. This was far less than the U.S. Navy minimum of $140^{o}F$. for shipboard use. The blend was further processed to remove the highly volatile light ends. Testing was first done on a stationary DDG-15 class boiler to establish feasibility, and subsequently on a sea trial on the U.S.S. Johnston (DD821). The tests revealed that it is indeed feasible to use synthetically derived oil as a marine fuel. Boiler performance was very similar to that obtained with diesel marine fuel. The only modification to normal operating procedures was that tank heating coils had to be activated because of the oils' low pour point. No detrimental effects to combustion equipment were noted.

There is little doubt that coal derived liquid fuel can substitute for petroleum based fuels. The problem is supply. At present, there exists no commercial industry to produce these fuels. But processes for the production of clean liquid fuels from coal are presently at an advanced stage of development. Pilot plants representing several

hundreds of millions of dollars of private and government capital are now operating, or committed to design and construction. This technology could be expected to be ready for commercial commitment in the 1980-82 period.[12]

There are three general technical approaches to the production of coal liquids:

1. Direct Liquefaction. Coal is slurried in a recycle solvent and is reacted with hydrogen. Up to 90% of the carbon is converted to a liquid or a clean solid form.

2. Coal Pyrolysis. Coal is subjected to heat, either with or without the influence of hydrogen. Part of the carbon is recovered as liquid and gas, and the remainder becomes a solid char product.

3. Indirect Liquefaction. Coal is gasified, and the gas produced is chemically reacted to produce a liquid product.

Among these choices, direct liquefaction is presently the preferred route, from the standpoint of yield and cost. Three developments are in leading contention in this field:

SRC (Gulf) - This process uses hydrogenation without

a catalyst and produces a high melting point liquid (400°F). A 50 ton/day demonstration plant has been operated at Tocoma, Washington, under ERDA auspices, and a 6 ton per day unit has been operated at Wilsonville, Alabama, under the supervision of EPRI and ERDA, and managed by Southern Company Services. Ash separation from the final product remains a development problem. Development is underway on a new version (SRC-II), which hopes to achieve a more conventional liquid product.

H-Coal (Hydrocarbon Research, Inc.) - In the H-Coal process, coal is slurried in a recycle solvent which reacted with hydrogen in the presence of a catalyst. The product can be varied from a light material approximating crude oil, to a heavy material of predominately boiler fuel. A 240-600 ton per day demonstration unit is being built at the Catlettsburg, Kentucky refinery of Ashland, under the sponsorship of ERDA, EPRI, several oil companies, and the state of Kentucky.

Exxon Donor Solvent (EDS) - This processing technique has elements of both SRC and H-Coal, in that the coal reaction takes place in the absence of a catalyst, but

the recycle solvent is catalytically hydrogenated. Exxon is proceeding with a pilot plant with support from ERDA, EPRI, and other sources.

The H-Coal process has the greatest likelyhood of early success, based upon the advanced development state of this process, and the form of the product as a pumpable, storable liquid, interchangeable in large measure with residual fuel oil. There are also indications that the Northeast Coal Utilization Program (NECUP) will undertake a building program to develop a liquid coal fuel route based upon the H-Coal process. This would serve to mature the technology, and would provide the necessary data for a commercial-scale venture.

IX. Conclusions And Recommendations

The world shortage of petroleum is real. Any attempts to alleviate the problem, short of finding a new fuel route based on other base stocks of natural resources, will only serve to delay the inevitable.

The most likely replacement sources for petroleum in the United States will be from oil shale and coal, our most abundant sources of hydrocarbon fuel. Coal is the more likely replacement fuel for petroleum, for the following reasons:

. A large, well established mining industry exists. Its technology is advanced and tested.

. The environmental impact of increased coal production is less than that which would result in establishing a large scale oil shale operation. Oil shale development would require large amounts of water in a region where water is scarce and is largely committed for other uses.

. In terms of money being spent by the government, coal receives 10 times the amount being spent on oil

shale. The ratio of private funds allocated for coal development with respect to oil shale, is even greater.

The Navy does not have the resources or the expertise to develop a new fuel route. Therefore, emerging fuel routes must be recognized, and their adaptability to the Navy's fuel needs must be factored into future ship design.

Coal derived liquid fuels offer the most palatable solution to the Navy's problem from a design standpoint. Current design practices and combustor technology would require little change. Existing ships could easily be retrofitted to accept a coal derived liquid fuel. If there were no problems with liquid fuels, the decision would be simple. But there are problems, and they must be dealt with. The synthetic liquid fuel industry is still in the planning stages. There are uncertainties as to future supplies, and costs of these supplies. There is also uncertainty as to the form of the final product. If H-Coal becomes the preferred process, the impact on ship design is negligible. This is not so with the other liquefaction processes.

The final and most important problem is resource depletion. The conversion step in processing coal into a liquid fuel consumes energy at a significant level. For current liquefaction processes, about 40% of the total

energy available in the raw coal, is consumed to convert it to a more convient form of fuel. This is a high price to pay for convience, especially light of the current problem of depleting petroleum supplies.

Solid coal burning (using AFB and PCF) reduces the resource depletion problem, but it requires a larger ship. Coupled with the increased ship size, come changes in design practices and combustor technoloty. Solid coal burning offers no solution to the fuel problems of existing ships, since total conversion would be too costly. A change to coal burning would present a period of difficult transition for the Navy.

Perhaps the difficulties will not seem so great, when necessity becomes the deciding factor.

Certainly the potential for coal use as a fuel, be it in the form of a liquid, solid, or slurry, is sufficient to warrent serious consideration.

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